# VALUATION METHODOLOGY OF DISTRIBUTED ENERGY RESOURCES PORTFOLIOS BASED ON AN ELECTRIC GRID BUSINESS MODEL INNOVATION FRAMEWORK FOR RENEWABLE ENERGY INTEGRATION

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# VALUATION METHODOLOGY OF DISTRIBUTED ENERGY RESOURCES PORTFOLIOS BASED ON AN ELECTRIC GRID BUSINESS MODEL INNOVATION FRAMEWORK FOR RENEWABLE ENERGY INTEGRATION

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*To my wife Laura,*

*my parents Julio Francisco and Enna del Pilar,*

*my friends Andrés, Jaime, Sebastián and Andrés,*

*the Ecuadorian people and all those that add value to our lives.*

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## LIST OF SYMBOLS AND ABBREVIATIONS

| | |
|---|---|
| BCA | Benefit-Cost Analysis |
| CA DRPs | California Distribution Resources Plans |
| COS | Cost of Service |
| CPUC | California Public Utilities Commission |
| CVAR | Conditional Value at Risk |
| DERs | Distributed Energy Resources |
| DERSP | Distributed Energy Resources Services Platform |
| DEREVA | Distributed Energy Resources Economic Value Added |
| DR | Demand Response |
| DSO | Distribution System Operator |
| DG | Distributed Generator |
| EV | Electric Vehicle |
| ES | Energy Storage |
| ESCO | Energy Service Company |
| ISO | Independent System Operator |
| MIP | Mixed Integer Program |
| NEM | Net Energy Metering |
| NERC | North American Electric Reliability Corporation |
| NPV | Net Present Value |
| NY REV | New York State Reforming the Energy Vision |
| NYPUC | New York Public Utilities Commission |
| LNBA | Locational Net Benefits Analysis |

| | |
|---|---|
| LMP | Locational Marginal Price |
| OMF | Open Modeling Framework |
| O&M | Operation and Maintenance |
| PV | Photovoltaic System |
| RPS | Renewable Portfolio Standard |
| SIP | Stochastic Integer Programming |
| T-D | Transmission-Distribution |

# SUMMARY

This research presents a valuation methodology of distributed energy resource portfolios based on an electric grid business model innovation architecture for renewable energy integration. Adoption of distributed energy resources (DERs) such as solar photovoltaic generators, energy storage, demand response devices, energy efficiency and electric vehicles is rapidly growing. This creates complex challenges for electric utility planning and operations, as well as major effects for the electric utility business model. In response to this, regulatory entities are transforming their electric grid planning, operations, market processes, and utility business models to a model that is customer and DER-centric. In the near term, these regulatory reforms call for the valuation of DER portfolios to avoid traditional electric utility distribution investments by allowing customers and energy service companies to offer DER services as alternatives. Therefore, there is a need for new and integrated methodologies that enables valuating DER portfolios and comparing investment alternatives. Traditional valuation methodologies rely on average system-level input assumptions that do not take into consideration the locational and temporal value of DERs. In addition, the value of a DER depends on: the network topology, DER location, market constraints, and how the DER is operated. This research proposes a methodology to determine the net value of a DER portfolio that consists of: 1) a system-level architecture to identify the market regulations and market actors, 2) a prosumer-based benefit-cost framework, 3) an economic-emissions optimization at the bulk power system, 4) a DER portfolio economic schedule optimization at the distribution system, 5) a two-stage stochastic optimization-based valuation methodology of DER portfolios and economic impact metric. The simulation results show that the framework can provide electric utilities and regulators with a valuation methodology to quantify the value of a DER portfolio located in a distribution circuit under different scenarios of DER forecast, location and dispatch schedules.

# CHAPTER 1. INTRODUCTION

This research presents a valuation methodology of distributed energy resource (DER) portfolios based on an electric grid business model innovation architecture for renewable energy integration. Customer adoption of distributed energy resources such as solar photovoltaic (PV) sources, energy storage (ES), demand response (DR) devices, energy efficiency (EE) and electric vehicles (EV) is expected to grow in the coming years. This creates complex challenges for electric utility planning and operations, and major impacts on the regulated utility business model. In response, several regulatory entities are transforming their electric grid planning, operations, market processes, and utility business models to a model where DERs and customers become the center of their operations and planning. In the near term, these regulatory reforms call for the valuation of DER portfolios to avoid traditional electric utility distribution investments by allowing customers and energy service companies to offer DER services as non-wires alternatives. A DER portfolio represents a set of DERs that can be composed of PV, ES, DR, EV whose valuation and investment or services procurement decision-making needs to be made by a certain electric utility. Therefore, there is a need for a comprehensive methodology that allows: 1) to quantify the value of DER portfolios and compare investment alternatives and 2) to assess the specific business-model economic impacts under different scenarios of DER forecast, location and dispatch schedules.

## 1.1 Traditional Utility Business Model: Cost of Service Regulation

A business model can be defined as how an organization creates, delivers, and captures value [3]. A company captures value by generating profits which represent the difference between revenues and expenses. In a non-regulated business, businesses set the price for their services based on market conditions and generate profit by revenues exceeding costs. Electric utilities are regulated businesses and natural monopolies [4]. While there are several variations, the traditional electric utility business model is founded on cost of service (COS) regulation [5]. In COS regulation, the electric utility state regulators -Public Utility Commissions (PUC)- set electricity rates based on the electric utility's incurred cost of providing service to customers during a specific year [6]. Figure 1 shows the schematic view of the traditional electric utility business model.

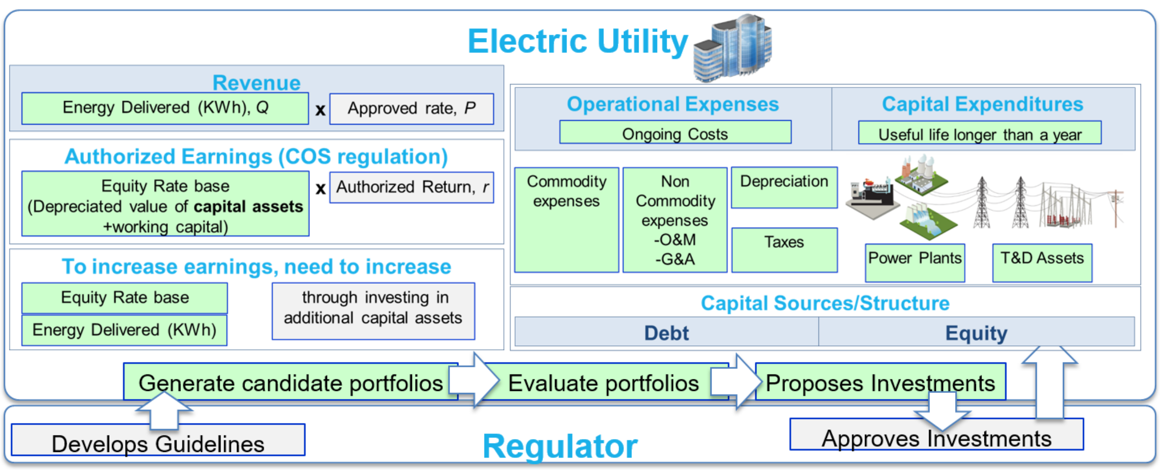


**Figure 1 – Traditional Regulated Electric Utility Business Model Diagram**

The COS business model can be roughly summarized as follows: electric utilities invest in projects aligned with the regulators' objectives (universal and reliable power delivery) and are allowed a rate of return (mostly on capital investments) to be recovered via electricity rates. Under the traditional COS model, a revenue requirement is determined so that all of the utility's costs, including a return on investment (profit), are covered. Electric utility costs consist of rate base (capital expenditures) and operating expenses [7]. The rate base consists of the un-depreciated balance of capital investments. The cost of service that should be recovered via rates is known as revenue requirement and is the combination of operating expenses and the return on rate base.

### 1.2 Need for New Business Models

The first business model innovation in the electric power industry was to move from local generators to central generating plants. Since then, the utilities business model has been characterized by a grow and sell strategy where utilities incur in capital expenses such as distribution system upgrade projects to deliver universal, reliable power to users and receive reciprocal value in the form of revenue, under the assumption that demand will continue to grow [8]. However, this model faces several challenges including:

1. Consumers want more control and information over their expenditures, environmental impact and their energy usage [8];
2. Sustainability and environmental objectives related to reducing carbon emissions require deploying higher amounts of DERs and intermittent renewable generation [9];
3. The electric infrastructure and workforce is aging. For example, it is expected that a $30 billion capital investment is needed in the next ten years in the State of New York [10];
4. DER costs including solar and storage are declining and efficiencies improving [11];
5. Regulatory policy, high competition, declining sales, decreasing profit margins, a shrinking customer base, and potentially stranded assets also affect the business model [12].

6. Electric utilities' profits are directly a function of their capital expenditures and depend on the assumption of load growth. However, several regions are seeing demand reduction and load growth decrease [7].

The recent challenges show that a business-as-usual approach is not the only cost-effective way of meeting utilities' responsibility for providing universal, reliable power at a reasonable cost [10]. The traditional operation has required utilities to deliver power to customers from centralized coordination of large power plants. Most customers have small or no participation in addressing system needs. Distributed energy generation (such as customer-owned renewable generation i.e. solar panels) and storage (electric vehicle, battery, etc.) allows the consumer to not only consume, but also to produce or store electricity. They become prosumers [13]. At the same time, control and communications allow utilities to coordinate DERs. These changes can have a major impact on the traditional electricity business model, allowing prosumers to participate in the value chain by offering new value-added services that include energy, capacity, ancillary services, or storage capabilities. Therefore, DERs combined with communication, control and market mechanisms provide utilities with the capability to capture the value of third-party prosumer-sited resources to integrate renewable generation, reduce overall costs, and improve reliability. Given that under traditional COS most utilities cannot earn a return on operating expenses, electric utilities' profits are directly a function of their capital expenditures and depend on the assumption of load growth. However, DER integration might involve decreases in net load and utility capital spending and increases in operating expenditures [7]. Therefore, new business models are needed to integrate DERs, because of the financial misalignment between the objectives of prosumers, electric utilities' economic objectives, and energy service companies or DER providers.

### 1.3 Need for a New DER Valuation Methodology

The value of a DER depends on a set of variables including: the network topology, the location of the DER in the network, the device operational constraints, and how the device is operated [14]. Traditional valuation methodologies rely on average system-level input assumptions that do not take into consideration the locational and temporal value of DERs [15]. First, they lack location-specific information. This is important because the value of a DER depends on where the DER is located in the distributionnsystem (i.e. PV output and line losses values in downtown areas are very different from PV output and line losses in rural areas). Second, they do not consider intertemporal constraints. For example, for energy storage the decision to charge or discharge in the morning affects the power that can be used in the afternoon and vice-versa. Also, most utilities use only a static steady-state analysis that focuses on peak system conditions of worst-case scenarios and static DER profiles [15]. Several utilities have recognized that static power flow analysis is not sufficient to capture the variability of DERs and are using time-series analysis [16] to capture some of the chronological effects. However, there is still a major gap in the current DER planning methodologies, which do not include an economic optimization approach that considers DER locational and temporal constraints. Economic optimization is needed for several reasons:

1. Optimize investment decision-making: to make the most effective use of resources when deciding in which DER portfolio to invest;

2. Optimize operational cost: to obtain the maximum value from DER portfolio services while considering locational and temporal constraints;
3. Consider intertemporal (look ahead) effects of current actions.

This research develops a DER valuation methodology to determine the net value of a DER portfolio. The methodology consists of: 1) a system-level architecture to identify the market regulations and market actors and their interrelations, 2) a prosumer-based benefit-cost framework to identify DER services or value categories, 3) an economic optimization at the bulk power system level, 4) a DER portfolio economic optimization at the distribution system, 5) an optimization-based valuation methodology of DER portfolios. The methodology will allow electric utilities to calculate the locational net value of DER-portfolio impact under different scenarios of load growth, DER forecast, location, and DER dispatch schedules.

## 1.4 Impact on the Electric Grid Business Model Innovation

The proposed research aims to contribute to the ongoing electric grid business model innovation process by providing electric utilities and regulators with a DER valuation methodology to quantify the economic impact of transforming their current business model of investing in traditional wires projects to a model of delivering value and generating profits by investing, procuring and facilitating customer-centered DER services.

## 1.5 DER Portfolio Valuation Methodology Statement of Objectives

The objective of the DER valuation methodology is to find the economic value of a DER portfolio taking into consideration system and locational-temporal DER constraints such as: the network model, DER type, location and operational constraints, and load forecast in a period of time. The following question is to be answered: What is the economic value of investment in a DER portfolio given price forecast, load forecast, distribution circuit model and DER operational constraints?

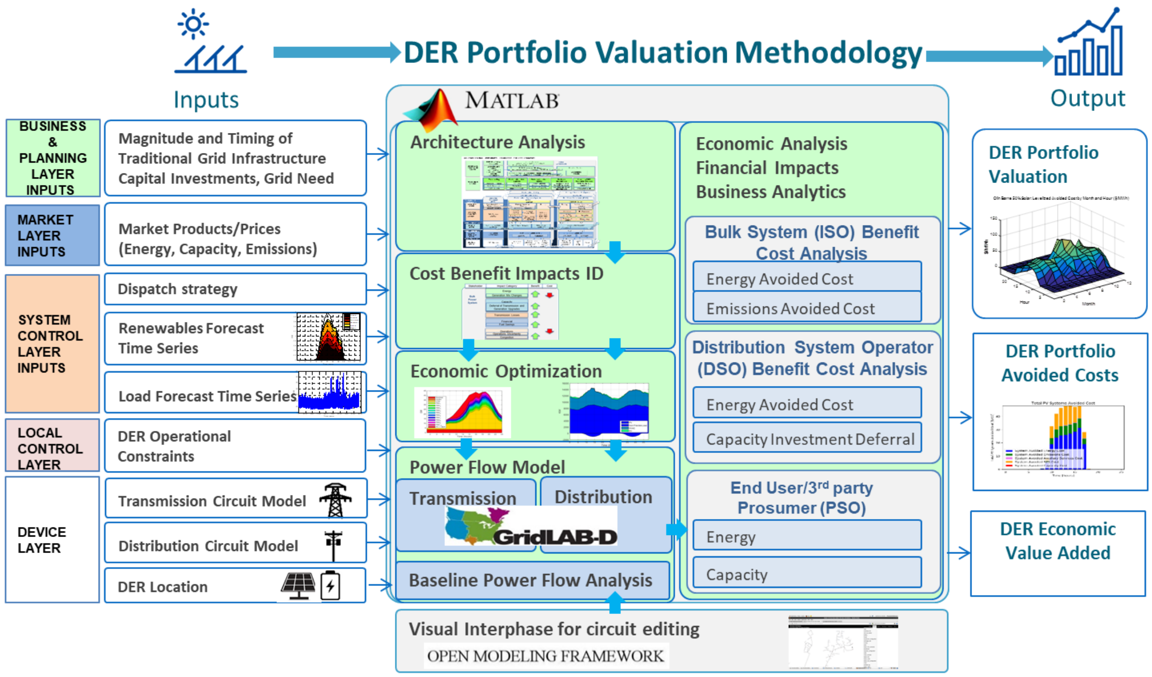


**Figure 2 – Schematic View of the Proposed DER Portfolio Valuation Methodology**

Figure 2 shows an overview of the methodology. In order to conduct a valuation of the DER portfolio investment, the following qualitative and quantitative analyses ought to be made:

1. **Architectural Analysis:** qualitative identification of market actors (independent system operator, distribution system operator, energy service company, residential, commercial, industrial customer), market rules and interactions.
2. **Identification of Benefit-Cost Value Categories:** identification of the value-categories (i.e. energy services), and allocation to the market actors.

3. **Bulk Power System-Level Economic Optimization Analysis:** economic dispatch optimization and impacts assessment at the bulk power system level.
4. **Distribution System-Level Economic Optimization Analysis:** economic dispatch optimization and impacts assessment at the distribution system level.
5. **Optimization-Based DER Portfolio Valuation**: net present value of the DER portfolio investment and annual operation under a specific DER schedule, and economic impact metrics such as avoided costs for DER portfolio value comparison.

### 1.6 Organization of the Document

This document is organized into seven chapters. In chapter II the electric grid business model innovation framework based on a DER energy services platform is presented. Then, chapter III describes the prosumer-based Benefit-Cost framework for valuation of DERs. Chapter IV presents the economic emissions dispatch for assessment of the impacts that aggregated DERs can have on the operational cost of the grid. Next, chapter V describes the DER portfolio economic optimization at the distribution level. Then, chapter VI presents the DER locational valuation based on a two-stage stochastic optimization model with risk averse considerations. Finally, the summary of contributions and future research directions is presented in chapter VII.

# CHAPTER 2. DER ENERGY SERVICES PLATFORM ARCHITECTURE

## 2.1 Introduction

This chapter introduces the foundational system architecture that is the first step in the DER portfolio valuation methodology. This work is described in reference [17] and some sections have been reproduced here. A Distributed Energy Resources Services Platform (DERSP) based on a Decentralized Grid Architecture is proposed as a Business Model Innovation Framework for the planning and coordination of DERs and renewable energy integration. The platform is based on a decentralized and layered architecture and is centered on the concept of electricity prosumers – economically-motivated agents (residential, commercial, industrial) – that can produce, store or consume energy. The platform consists of seven layers, including: the physical layer, local control layer, cyber layer, system control layer, market transactive layer, planning layer, and business layer. The contributions of this work are expanding the prosumer-based decentralized architecture [13], [18] by: a) formally identifying market actors, services exchanged and mapping system modules interrelations; b) proposing a new planning layer that describes how DER portfolios services are identified, valued and sourced as alternatives to traditional electric utility investments by offering grid-related energy services; c) proposing a new business layer that provides a framework for investment decision-making that uses an optimization-based locational value assessment of traditional and non-traditional (DER) capital investments while considering the regulatory environment, market rules, business objectives, planning constraints, system constraints, device constraints and grid model specified by the lower layers of the architecture. The DER energy services platform architecture represents a high-level description of the complex electric grid system. The main objective of the platform is to provide a framework for the business model innovation based on a system-level model which encompasses several simultaneous, spatially-distributed and heterogeneous electric grid sub-systems containing energy resources, and decision agents with different objectives, at different time scales and horizons in order to integrate higher amounts of renewable energy, while dynamically maintaining and adapting to user level of service requirements, system constraints, and market constraints.

This chapter is organized into four sections. In section 2.2 the literature survey on Electric Grid Business Model Innovation Frameworks is presented. Then, the proposed DER Energy Services Platform Architecture is described in section 2.3. Finally, conclusions are presented in section 2.4.

## 2.2 Electric Grid Business Model Innovation Frameworks

### *2.2.1 Recent Proposals for Electric Grid Business Model Innovation Frameworks*

Several innovation frameworks have been proposed in the last years. Figure 3 shows different frameworks that have been identified for electric grid business model innovation [19]. These models are shown sequentially depending on the level of regulatory change. The most transformational require significant regulatory modification. The transitory models intend to serve as a connection between current models and the more transformational ones.

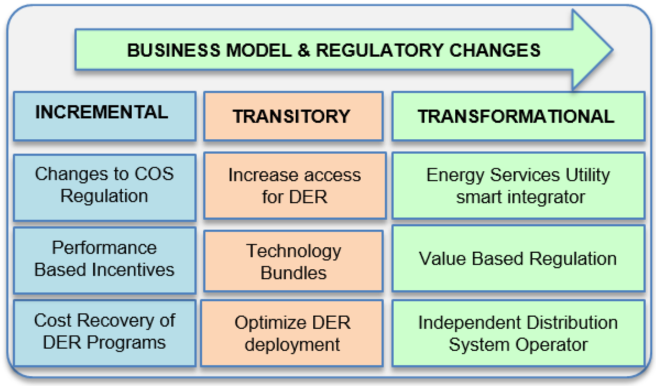


**Figure 3 – Business Model Innovation Approaches**

Some frameworks, such as the one proposed by American Public Power Association, consider that the market should retain key elements of the existing industry infrastructure [20]. Another proposal from the Arizona Public Service proposes a vertically-integrated utility business model which includes utility ownership of DERs [21]. The National Rural Electric Cooperative Association (NRECA) has proposed the electric cooperative model of consumer-oriented, consumer-owned, not-for-profit entity [22]. Others have been focused on the incremental reforms associated with the regulatory process and, in particular, have proposed performance-based regulation as an alternative [23]. There are other more transformational approaches, such as the one from former FERC chairman Wellinghoff that envisions a "transactive energy framework" in which several actors make value-based energy decisions and calls for the implementation of Independent Distribution System Operators that coordinate DER planning, deployment and dispatching [24]. Another transformational approach is the one proposed by former Texas Utility Commissioner, Rabago, who proposes a "sharing utility" that is based on consumer empowerment in the sharing economy and replaces cost-based regulation with value-based regulation [25]. In [26], a former Colorado Public Utilities Commissioner presents a staged approach which considers the maximum role of the utility as an "energy services platform."

While all of these frameworks touch on several important issues, there is no proposal for a methodical approach that allows the quantification of the benefits and the costs of a specific business model while taking into consideration system-level, operational, locational and temporal constraints of DER portfolios and specific dispatch strategies.

### *2.2.2 Distribution System Operators*

Recent efforts around the globe, including proposals like the New York State Reforming the Energy Vision (REV) [10], California PUC Distribution Resources Plan [27], and the United Kingdom RIIO [28], intend to transform the electric industry into a more sustainable, integrated, customer-oriented model where DERs become crucial instruments in the planning and operation of the interconnected grid. These frameworks call for the electric distribution utility to become a Distribution System Operator (DSO) or Platform (DSP), an entity that coordinates with consumers, prosumers, energy service companies and the ISO in order to integrate higher amounts of DERs and enable DER services. The DSO market proposed by REV and other regions has several characteristics of a multi-sided platform market with the utility acting as the platform provider [10]. In these types of markets, transactions take place in a multi-lateral way in which buyers, sellers, and the platform provider each interact. Recent advancements in digital business models such as UBER, Google and Airbnb are familiar examples of platform markets in the modern economy [29]. The platform, services-oriented business model consists of coordinating and aggregating a set of third-party assets (i.e. DERs) in a fragmented market and enabling the exchange of value-added services (i.e. capacity, energy, investment deferral) by connecting them in a network. The platform provides the protocols, environment, technology, and structure through which market actors can interact. One of the advantages of the concept of the platform provider is that it aligns well with recent literature on the value of networks [7] which states that a good is more valuable if it is part of a network of goods. For example, a residential prosumer that is able to shift power consumption might have limited local impact on the system value, but a coordinated portfolio of DERs can have substantial pricing and investment effects that have both local and system-level effects.

As Figure 4 shows, the framework proposed in [1] describes three conceptual distribution system operator models: Total ISO (where ISO models and optimizes the whole system), Minimal DSO (where the ISO models the DERs at the Transmission-Distribution (T-D) interface) and a Market DSO (where the DSO is the aggregator for all DERs below the T-D interface).

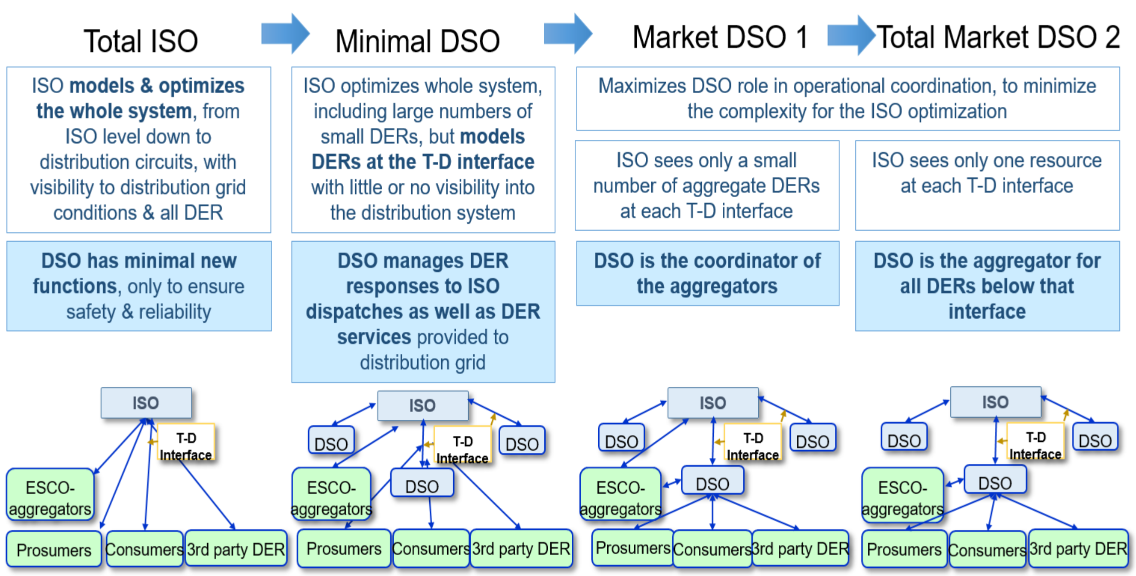


**Figure 4 – Conceptual Models of Future Grid Integrated Systems Operations: DER-DSO-ISO Interactions**

Electric utilities have different levels of DER adoption. The framework behind these proposals [1] has suggested a staged approach that considers different levels of DER adoption and new functions as shown in Figure 5.

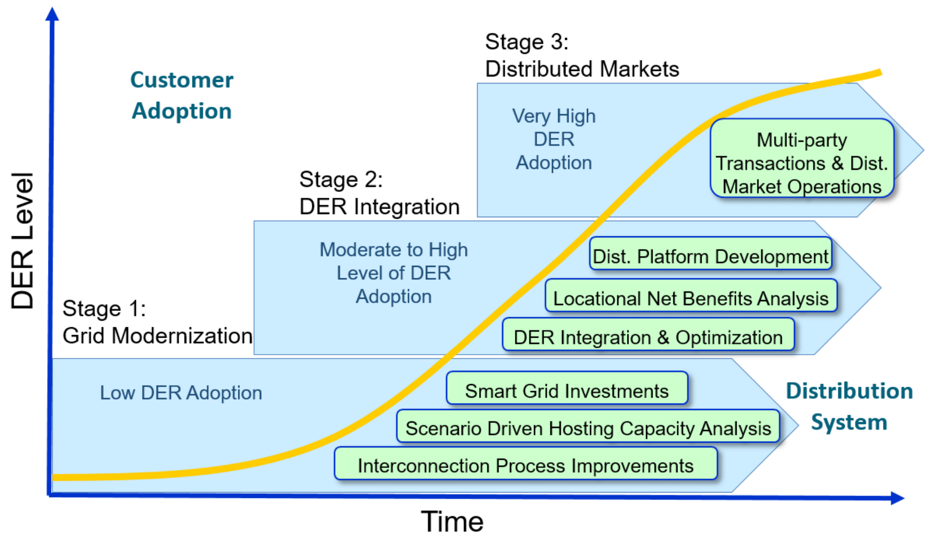


**Figure 5 – Stages of Distribution System Evolution [1]**

New planning, operations and market functions required in each stage are listed in Table 1 and include: hosting capacity analysis, locational net benefit analysis, integrated T-D planning; DER scheduling; and operation of distribution-level energy markets.

**Table 1 - Distribution Functions by Evolutionary Stage [1]**

| Distribution Functions | Stage 1 | Stage 2 | Stage 3 |
|---|---|---|---|
| **1. Planning** | | | |
| A. Scenario-Based, Distribution Engineering Analysis | ✓ | ✓ | ✓ |
| B. DER Interconnection Studies and Procedures | ✓ | ✓ | ✓ |
| C. DER Hosting Capacity Analysis | ✓ | ✓ | ✓ |
| D. DER Locational Value Analysis | | ✓ | ✓ |
| E. Integrated T&D Planning | | ✓ | ✓ |
| **2. Operations** | | | |

| | | | |
|---|---|---|---|
| A. Design-Build and Ownership of Distribution Grid | ✓ | ✓ | ✓ |
| B. Switching, Outage Restoration & Distribution Maintenance | ✓ | ✓ | ✓ |
| C. Physical Coordination of DER Schedules | | ✓ | ✓ |
| D. Coordination with ISO at T-D Interface | | ✓ | ✓ |
| **3. Market** | | | |
| A. Sourcing Distribution Grid Services | | ✓ | ✓ |
| B. Optimally Dispatch DER Services to Distribution Grid | | ✓ | ✓ |
| C. Aggregation of DERs for Wholesale Market Participation | | ✓ | ✓ |
| D. Creation & Operation of Distribution-Level Energy Markets; Transactions Among DERs | | | ✓ |

### *2.2.3 Decentralized Grid Architectures*

There are several challenges associated with planning and coordination of large numbers of renewable resources [30]:

1) Scalability to collect, integrate and manage several spatially distributed and heterogeneous devices;

2) Reliable coordination of DERs while: a) dynamically maintaining and adapting to quality of service requirements and system-level constraints, b) providing function and performance guarantees, in terms of speed, scalability, and privacy protection;

3) Identification of market actors, services and interrelations;

4) Business model framework and quantification of the benefits provided by DERs at different levels of renewable integration [31].

Considering that just a medium-sized distribution utility has thousands of nodes, it is not possible for a single organization to make all the operational decisions needed since this requires massive amounts of data, substantial communication, and the ability to solve intractable optimization problems [32]. These technical challenges require an overhauling investigation of the current system architecture. Therefore, there is a need for better electric grid planning and coordination architectures.

Grid architecture analysis has been defined in [33] as a system-level model which encompasses several simultaneous electric grid sub-systems and represents a high-level description of the electric grid and a key tool to help comprehend and describe the complex interactions that exist in present and future electricity grids. A formal prosumer-based decentralized control and management architecture for the grid was proposed in [13], [18].

In addition, several technological advances have been made to achieve the vision of a decentralized, customer-oriented, integrated grid. Also, decentralized energy scheduling applications have been developed, including: 1) advanced integrated optimization at the residential level [34]; 2) decentralized energy scheduling for large-scale systems [35]; and 3) distribution-level pricing methods [36]. These results demonstrate scalability that can be ported to the distribution-level operations and planning to address high levels of DER penetration. While several advances have been made in specific use-case modeling, the big question remaining is how to build a methodology that values the costs and benefits of several DER technologies in an integrated way. The vision of a more sustainable, customer-oriented, DER-value-oriented business model for the grid presents many challenges [10] including: 1) Creating a grid architecture to understand the complex interrelations of several subsystems; 2) Defining a benefit and cost framework for a utility's investment in DERs; 3) Defining a valuation methodology for DER portfolios services that can be transacted among stakeholders in the grid.

### 2.3 Electric Grid Business Model Innovation Framework based on a DER Services Platform Architecture for Renewable Energy Integration

In this study, a Distributed Energy Resources Services Platform (DERSP) is proposed as a Business Model Innovation Architecture Framework for Valuation of DER Portfolios and Renewable Energy Integration. This study extends the work in [13], [18] in three forms:

1. It formally identifies:
    (a) the market actors (ISO, DSOs, ESCOs, prosumers),
    (b) the services exchange between them (energy, capacity, ancillary services), and
    (c) the interactions between actors and system modules across the different architectural layers;
2. It includes a new business layer that provides a framework for investment decision-making by considering regulatory guidelines, business objectives, valuation of traditional and DER portfolios services as value propositions, investment decision-making, and
3. It includes a new DER planning layer that describes how DER portfolios services are identified, valued and sourced as alternatives to traditional electric utility investments.

Based on this concept, the multi-layered prosumer model that describes the grid interactions has been adapted from [9] for the DERSP case and is illustrated in Figure 6.

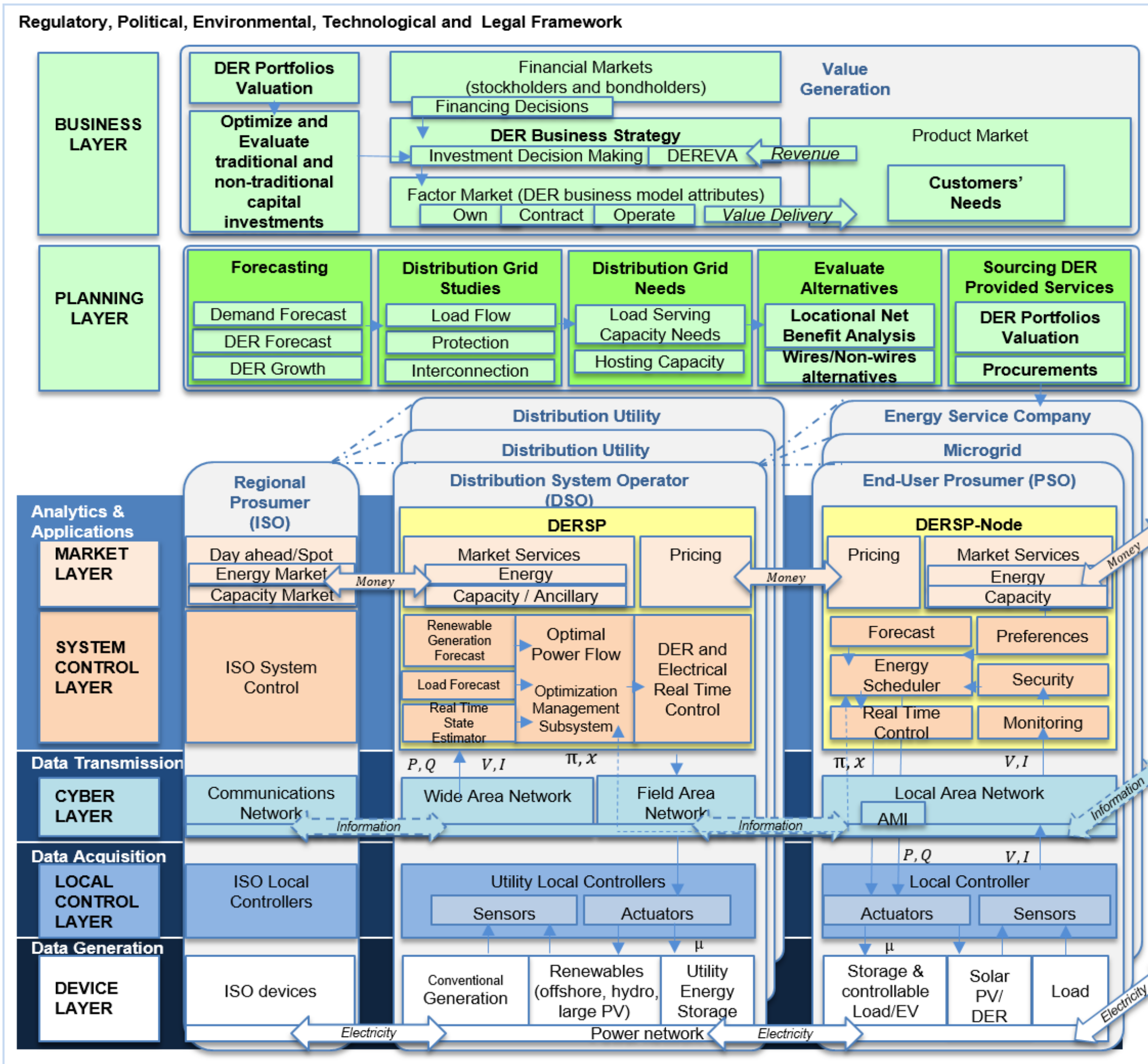


**Figure 6 – Distributed Energy Resources Services Platform Architecture**

The architecture incorporates various system components that reside in and form seven layers of an integrated decision-making system:

1. Device Layer: the grid, PV, energy storage (ES), electric vehicles (EV), and flexible load demand-response (DR) devices.

2. Local Control Layer: smart inverter controllers, sensors, actuators and local protections; and
3. Cyber-Layer: advanced metering infrastructure and communication infrastructure;
4. System Control Layer: monitoring, forecasting, secure optimization management and system-level real-time control;
5. Market Layer: pricing, and services exchange;
6. Planning Layer: forecasting, distribution grid studies and needs identification, locational valuation of DER portfolios and sourcing of DER services;
7. Business Layer: consideration of regulatory guidelines, valuation of traditional and DER portfolios services as value propositions, investment decision-making;

DERSP registers prosumer agents (residential, commercial, industrial, microgrid, ESCOs, aggregators), grid spatial divisions based on ownership or management of DER assets. The prosumer agents expose their services/requests and prices (x, $\pi$) to the platform based on load and renewable generation forecasts, generation profiles and the characteristics of their controllable devices, including flexible storage. Prosumer agents are not homogenous. Therefore, all users are able to decide their own comfort level and objective functions. The platform includes the consideration of communication and metering infrastructure in the cyber layer, to consider data transmission to and from devices, which enables connectivity and interoperability. Taking into consideration DER profiles, non-controllable load, and grid constraints, the DERSP determines the optimal economic schedule of energy operations and reserves. If decided, the platform enables the surplus energy to be traded in the reserve or energy market and allows for different prosumers (homes, microgrids) to be clustered into super-prosumers that expose aggregated virtual capabilities such as dynamical net-load shaping to the ISO or equivalent control center entity.

### *2.3.1 Business Layer*

The business innovation framework builds upon the prosumer-centered approach and allows different prosumers to decide on their grid objectives associated to ultra-reliability, economic optimization and sustainability. The architecture incorporates the notion that customer-owned renewable generation like solar panels and storage allows the consumer to not only consume but also to produce or store electricity. This combined with two-way communication changes the traditional electricity business model and allows consumers to participate in the value chain by offering new value-added services that include: demand response, energy reserves, power, storage capabilities, information about consuming patterns and several other services. The business layer is intended to help an electric utility to select its investments in specific DERs, renewable energy products and services across the value chain (physical, local control, communications, system control, market) in order to modify or leverage its core capabilities and improve its economic value creation. In order to make the best decisions regarding its investment policy, the electric utility can decide to implement a set of value levers including: own, contract, or operate DERs while considering requirements across the different layers. This multidimensional approach can help to improve the company's performance as measured by its return on invested capital.

Existing electric utility business models are not able to tap into the potential value of DERs to meet grid and society objectives of economic operation, reliability and environmental sustainability. Several new business models emerge through the aggregation of the distributed capabilities of prosumers. Examples include: 1) transactional platforms 2) energy service platforms that connect networks of prosumers to offer services to the bulk power grid. In order to analyze these new models a formal new business model innovation tool based on [3] is proposed and is shown in Figure 7.The main objective of a business model is to create, deliver, and communicate superior customer value in order to achieve and sustain long-term competitive advantage. There are two main steps used to achieve this objective:

1. Environment Analysis 5Cs: Company, Customer, Competition, Collaborators, Context
2. Implementation Analysis 4Ps: Product, Place, Price and Promotion

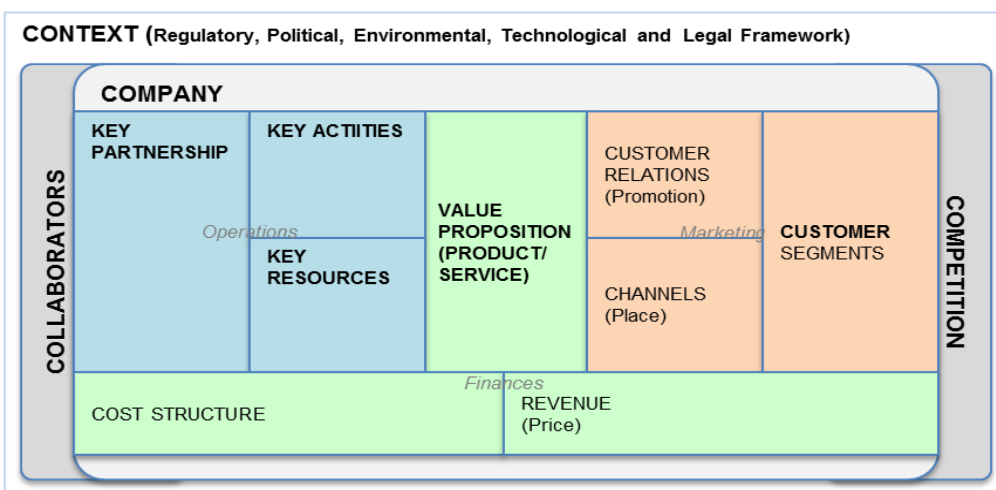


**Figure 7 – DER Business Model Innovation Framework (Adapted from [3])**

Products and services can be exchanged between the DERSP and the owner of the DER, or with an energy service company (ESCO) that aggregates the capabilities of individual prosumers. Some of the products and services include but are not limited to: energy, reserves, distribution deferral capacity services, reliability services, among others. The following chapters will explore the valuation of different DER services looking at the revenue and cost structures, device constraints, system-level constraints and market constraints. The sections associated with collaborators, competition, customer relations, channels, key activities, resources, and partnerships are out of the scope of this research.

A simplified approach to calculate the total electric utility net income under a traditional COS was proposed in [6]:

$$NI = P \cdot Q - [(VCC \cdot Q) + (VNCC \cdot Q) + FNCC + (r \cdot RB)] \tag{1}$$

Where $NI =$ Net income or profit, $P =$ Approved rate, $Q =$ Quantity of retail electric sales, $VCC =$ Variable commodity costs, $VNCC =$ Variable non-commodity costs, $FNCC =$ Fixed non-commodity costs (taxes, depreciation, and debt costs), $r =$ Overall rate of return $RB =$ Ratebase (i.e., net investment in assets to provide electric service). In this model the electric utility is motivated to increase investment in capital assets and increase the volume of commodity sales. Some incremental changes include, 1) fuel-adjustment clause where the motivation is to increase retail commodity sales and reduce fixed-non-commodity sales; 2) Lost revenue mechanism: it deals with the under-recovery of fixed costs; and 3) Shareholder incentive mechanism: that provides compensation based on energy savings.

$$\Delta NI = COS - \Delta FNCC + LRRM + SI \tag{2}$$

Where $LRRM$ is a lost revenue recovery mechanism, and $SI$ is the stakeholder incentive. Other more fundamental changes include a services-driven model where the utility focuses on offering value-added services (energy efficiency, etc.), and a value-driven model

$$NI = \left((P_Q \cdot Q) + (P_S \cdot S)\right) - ((VCC \cdot Q) + (VNCC \cdot Q) + (VSC \cdot S) + FNCC + (r \cdot RB)) \tag{3}$$

$$NI = \left((CapP_Q \cdot Q) + (CapP_S \cdot S)\right) - ((VCC \cdot Q) + (VNCC \cdot Q) + (VSC \cdot S) + FNCC + PBR\ Profit\ Provisions) \tag{4}$$

Where $P_Q$ is the price of retail electric commodity sales and $P_S$ is the price of retail value-added services, $S$ are the services, $VSC$ is the variable value-added service costs, $PBR\ Profit$ is a performance-base rate provision, and $CapP_Q$, $CapP_S$ represent cap-prices.

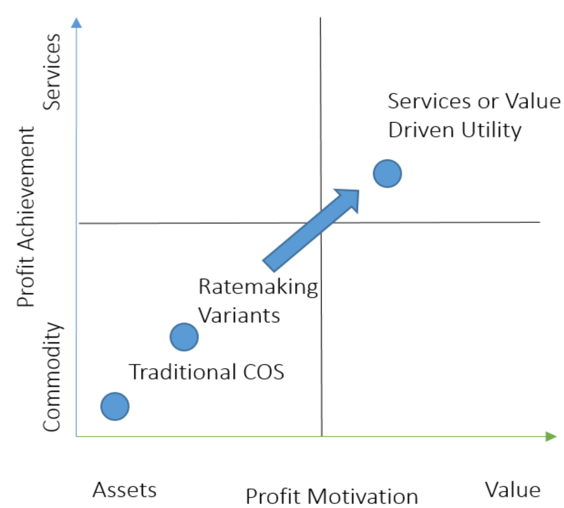


**Figure 8 – Business Models Profit Motivation and Profit Achievement [6]**

### 2.3.2 Traditional Distribution Planning Process

The objective of distribution planning is to maintain a reliable electric system operation and to guarantee the availability of capacity and operating flexibility for the distribution grid. The distribution planning process consists of the following steps [37]:

1. Creating forecasts for peak demand and load growth;
2. Identifying distribution capacity requirements by simulating the electric grid behavior under the forecasted scenarios (load, peak demand) using power-flow modeling tools;
3. Developing, valuating and executing distribution capacity projects or programs that meet the identified distribution capacity requirements due to the forecasted scenarios.

Currently, most utilities have traditionally used static steady-state analysis that focused on peak system conditions of worst-case scenarios [15]. While several utilities are beginning to recognize that the variability of DERs requires not only a static load flow analysis but a time series analysis [16], there is still a gap in recognizing that the planning of DERs requires an optimization approach that considers time and locational DER constraints.

### 2.3.3 Planning Layer

In the last decade, the distribution planning processes in regions like CA, NY, and HI have evolved to integrate more DERs. For example, since 2001 the CPUC has determined that [27] each electric utility, as part of its distribution planning process, needs to consider DERs as a potential alternative to traditional distribution system investments in order to guarantee economic and reliable electric service.

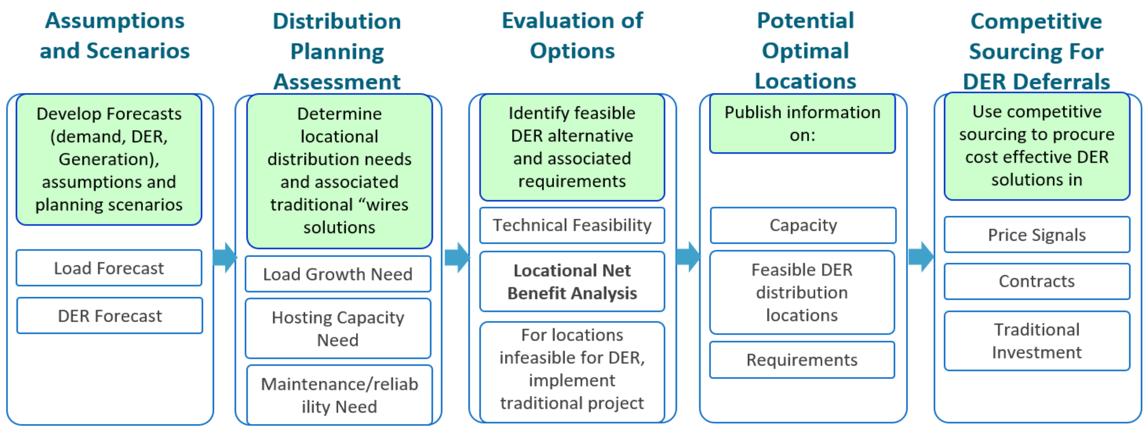


**Figure 9 – New Planning Layer based on Evolving Distribution Planning [38]**

Figure 9 shows the new planning layer based on evolving distribution planning discussions [38], [39]. Under this framework the distribution planning process consists of:

1. Forecasting load and peak demand.
2. Distribution Planning Assessment: Using power-flow on circuit models with expected forecast in order to determine needs that satisfy:
   (a) Hosting Capacity Need: i.e. thermal ratings of equipment are within limits.
   (b) Load Growth: Customer Voltage stays within corresponding standard.
   (c) Reliability Need: Customer outage is limited.
3. Locational Benefit Analysis: Conduct a technical feasibility and Benefit-Cost Analysis of a DER Portfolio based on grid needs.

4. Publishing information on integration capacity maps, deferral opportunity locations and technical requirements. In particular, for projects where DER deferral is potentially feasible, the following needs are determined:
   (a) Service required: energy, capacity, peak shaving;
   (b) Magnitude/quantity of service;
   (c) Timing for deployment;
   (d) Specific operational requirements for duration cycling (i.e. 4-hour duration, every weekday evening, summer season); Control/dispatchability requirement.
5. Using competitive DER sourcing and DER portfolio valuation to procure cost-effective DER solutions. The highest net benefit solution is selected.

## 2.4 Summary

This chapter has presented a Distributed Energy Resources Services Platform Architecture (DERSP) as a Business Model Innovation Framework for the Planning of Distributed Energy Resources and Renewable Energy Integration. The framework is based on a multi-layered architecture. The architecture consists of seven layers that manage: 1) Devices, 2) Local controllers, 3) Data transmission, 4) System controllers, 5) Market, 6) Planning and 7) Business decision-making. The framework allows electric grid actors to better understand the complex interrelations of prosumers subsystems equipped with DERs in order to integrate higher amounts of renewable energy. This work has extended previous work on decentralized grid architectures by: 1) formally identifying (a) the market actors (ISO, DSOs, ESCOs, prosumers), (b) the services exchanged between them (energy, capacity, ancillary services), and (c) the interactions between actors and system modules across the different architectural layers; 2) It includes a new business layer that connects investment decision-making with the rest of the layers; and 3) It includes a new DER planning layer that describes how DER portfolios services are identified, valuated and sourced as alternatives to traditional electric utility investments.

# CHAPTER 3. PROSUMER-BASED BENEFIT-COST FRAMEWORK

## 3.1 Introduction

This chapter presents the prosumer-based benefit-cost framework that is the second step in the DER portfolio valuation methodology. This work is described in reference [40] and has largely been reproduced here.

The electric power landscape is undergoing a profound change driven by a confluence of environmental concerns, economic forces, regulatory trends and significant advances in technology. The traditional electricity business model has been characterized by a centralized architecture where utilities deliver power from centrally coordinated generators and receive revenue based on volume of energy sales. The introduction of distributed generation and storage allows traditional consumers to not only consume, but also to produce, or store energy. The active participation of these so called “prosumers” transforms the traditional electricity business model and allows them to participate in the value chain by offering new services. However, how these capabilities should be valued, planned and integrated into the overall system operation is unclear. There is a need for a new benefit-cost framework that provides stakeholders the insight they need to make informed investment decisions. This chapter presents a prosumer-based, benefit-cost and business model innovation framework for the valuation of distributed energy resources. The framework provides electric utilities, energy service providers and prosumers the foundation to evaluate the net benefits of distributed energy resources.

This chapter is organized into four sections. In section 3.2 the literature survey on DER Valuation Methods and Benefit-Cost Frameworks is presented. Then, the proposed Prosumer-Based Benefit-Cost Framework for Valuation of DERs is described in section 3.3. Then the Locational Valuation for DER Services is presented in section 3.4. Section 3.5 presents simulation results. Finally, a summary is presented in section 3.5.

## 3.2 DER Valuation and Benefit-Cost Methods

### *3.2.1 CA Distribution Resources Plans and NY Reforming the Energy Vision*

Motivated by the challenges described in section 1.2, there are two fundamental regulatory reforms that are taking place in California and New York to incorporate DERs as part of utilities' planning, operations and utility business models. In CA, after Assembly Bill (AB) 327 the California Public Utilities Commission (CPUC) issued the DRP ruling [41] that required utilities to submit a Distribution Resources Plan (DRP) that includes the development of a locational net benefit analysis (LNBA) that describes locational benefits, costs and optimal locations of DERs [27].

In the State of NY, the Reforming the Energy Vision (REV) proceeding calls for the transformation of Electric Utilities into DSOs that make customers and DERs the center of their planning and operations. As part of this effort the NY Public Utilities Commission (NYPUC) considered that costs can be reduced, and efficiency can be increased if DERs are properly valued and compensated for their services to the grid. In consequence, it developed a Benefit-Cost Analysis (BCA) framework [42] to evaluate the cost effectiveness of DER programs and informs utility decision-making.

### 3.2.2 Locational Net Benefit Analysis and Benefit-Cost Analysis

The DER valuation literature can be classified into: Benefit-Cost Analysis (BCA) Frameworks, and Locational Net Benefit Analysis (LNBA) Methodologies. Some of the early studies proposed a BCA framework that builds on [43] PURPA incremental or avoided costs methodologies or energy efficiency screening methods [44] and describe the traditional approaches to account for DER impacts:

1. Direct Monetization: the favored method to value DER impacts;
2. Proxies: this method uses multipliers (to avoided costs, etc.) to approximate value categories for which direct monetization is not available;
3. Alternative Benchmark: uses a predetermined benefit-cost ratio and eliminates the need of using DER value categories,
4. Regulatory Judgment: regulators make the determination that a DER portfolio is cost effective without monetization or an alternative benchmark;
5. Multi-Attribute Decision Analysis: a systematic process that weighs and scores both monetized and non-monetized criteria.

BCA frameworks such as the ones proposed by NY utilities in [45], [46], [47], [48] describe a set of value categories and structure in order to assess the value of DERs. The list of value DER categories included in the DERAC, CPUC, and NYPUC is shown in Figure 10.

| E3 DERAC Components |
| --- |
| Energy |
| Losses |
| Generation Capacity |
| Ancillary Services |
| Environment |
| Avoided RPS |
| T-D Capacity |

| Color Code |
| --- |
| Generation |
| Transmission |
| T-D |
| Distribution |
| Externalities |

| CPUC Components |
| --- |
| Avoided Energy |
| Avoided Environmental GHG |
| T-D Losses |
| RA Capacity |
| Avoided Ancillary Services |
| Avoided RPS Expenditures |
| Avoided Renewable Integration Costs |
| T-D Capacity Expansion Deferral |
| Distribution P, Q Capital and O&M |
| Distribution Reliability & Resiliency Capital and O&M |
| Societal |
| Public Safety Avoided Costs |

| NYPUC Components |
| --- |
| Avoided Energy |
| Avoided Gen Capacity |
| Avoided Transmission Losses |
| Avoided Ancillary Services |
| Wholesale Market Impact (attenuation) |
| Avoided Trans Cap Infrastructure & O&M |
| Avoided Distribution Cap Infrastructure |
| Avoided Distribution O&M |
| Avoided Distribution Losses |
| Costs (program admin costs, lost utility revenue, |
| Avoided GHG |
| Net Non Energy Benefits |

**Figure 10 – DERAC, CPUC and NYPUC DER Value Components**

As described in [42], the BCA informs the electric utilities planning and decision-making by the quantification of the net present value (NPV) of a potential action, which could include: a DER or traditional investment, a purchase contract or portfolio, alternative tariff designs or alternative operating procedures. A parallel effort in CA [49] proposed the LNBA which lays down a set of value categories that capture the avoided costs resulting from DERs locally at the distribution system and at the bulk system level. This methodology is based on the CPUC cost-effectiveness DER avoided costs calculator (DERAC) which uses average system-level values [50].

Recent studies call for moving from conceptual valuation frameworks that identify potential net benefits categories to more detailed and quantitative methodologies [14]. A review of the PV benefit-cost methodologies was conducted by the RMI which reported sixteen different methodologies [51]. Most of these studies focus on system-level impacts and do not consider local distribution-level DER impacts. The studies in [52], [53] covered an overview of the methodologies for DER valuation and proposed a valuation methodology based on optimization. However, this study only considers PV and DR and does not take into consideration inter-temporal constraints imposed by ES. A recent study by EPRI, expands its integrated grid framework [54] to valuate DERs at two systems located in CA and NY [16]. This study uses time series analysis of power flow with static DER profiles which does not take into consideration DER operational-optimization or dispatch strategies.

A recent analysis [55] proposed an analytical methodology that goes beyond specification of BCA categories. However, it does not incorporate energy scheduling considerations which directly affect the value of DERs. Recently, a new methodology [56] by the NYDPS describes a transition plan for moving from net energy metering (NEM) to DER valuation built upon Locational Marginal Price plus Distribution Value (LMP+D). This methodology makes progress in considering a more granular, locational DER valuation, but only estimates a system-level averaged distribution value.

In conclusion, recent methodologies either propose BCA frameworks that only list a set of DER value categories or propose methodologies that only calculate average system-level DER impacts or are only based in time series power flow analysis with typical (static) DER profiles. Therefore, there is a fundamental gap in the valuation methodologies that do not include locational-temporal constraints of DERs and DER scheduling which directly affects the value of DERs.

## 3.3 Prosumer-Based Benefit-Cost Framework for Valuation of DERs

A prosumer-based benefit-cost analysis (BCA) framework is presented that combines and builds upon recent studies [57] and the value categories being discussed in California DRPs and NY BCAs [45] - [48]. The first step is the identification of the DER value chain segment. Then, the next step is the identification of market actors, market rules, and interrelations. Next, it is necessary to identify the potential service or value categories for DERs that will be exchanged (i.e. deferral of distribution capacity investment). Then, the impacts are classified as benefits or costs, and the costs and benefits are allocated to different stakeholders within the power system. The next step consists of identifying how the benefits can be monetized so that all the net impacts are quantified in financial terms. After this initial qualitative analysis, a quantitative analysis takes place. First, the specific DER scenario is created. A schedule of energy operations is obtained from the DER scheduling. Then, a quasi-steady-state-time-series (QSTS) power flow simulation is run to compare the DER scenario with the baseline feeder operation. Finally, the impacts on distribution and transmission are calculated.

### *3.3.1 Identification of DER Value Chain Segment*

The first step in the prosumer-based BCA consists of identifying a segment on the DER value chain for analysis. The DER value chain has been adapted from [58] and [59] and is shown in Figure 11. It is divided into four segments:

1. Manufacturing: It includes all hardware and DER devices: PV modules, storage, and installation materials and power electronic devices.

2. Marketing: This segment includes project development from design to installation.
3. Financial: This segment consists of the financial services and risk assessment.
4. Operations: This segment refers to the coordination of DERs to deliver energy, capacity and grid support services. It also considers maintenance, customer service and decommissioning.

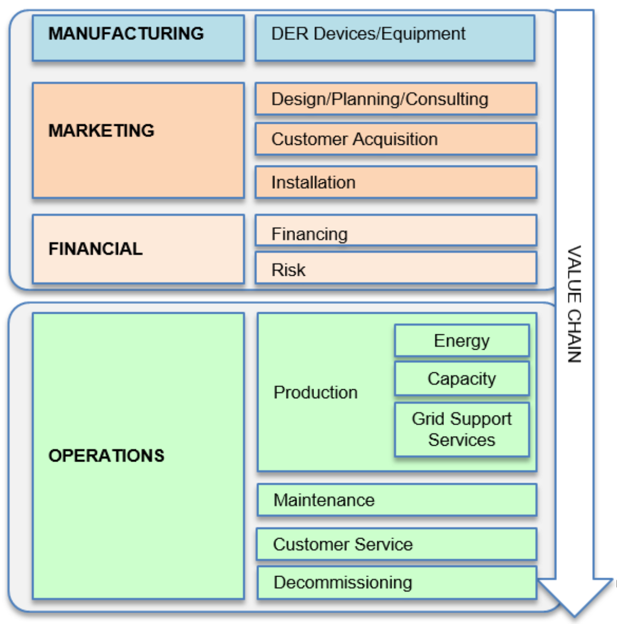


**Figure 11 – DER Value Chain**

In this study, the scope has been limited to electric grid services. Additional DER services such as financing, information value, etc. are out of the scope.

### *3.3.2 Identification of Market Agents, Market Rules, and Services Attributes*

The second step in the prosumer-based BCA framework consists of identifying the electric grid agents and their interrelations. Figure 12 shows a schematic view of the analysis to identify the market actors adapted from [60]. Consider a DER portfolio $P$. Let the DER portfolio be located at $C$ (residential, industrial, commercial) customers with some potential contractual relation $x_{PE}$ with ESCO $E$. The DER portfolio $P$ is located at distribution system $D$ and has impacts on bulk-transmission system $B$. The set of market rules $R$ determines that the portfolio can offer $x$ services that are transacted at price $\pi$. The services can be classified into: 1) distribution-level services (distribution capacity deferral), 2) bulk-system level services (energy, capacity, emissions), 3) ESCO services, 4) customer-to-customer level services.

The regulatory environment determines the set of rules $R$ which establishes: 1) market actors $(B, D, C, E)$, 2) their interdependencies and DER services transacted: (i.e. $x_{PB}$ =wholesale service direct to bulk-system, $x_{PD}$, $x_{PE}$, $x_{EB}$, $x_{ED}$, $x_{ED}$) ; and 3) corresponding monetization mechanisms $\pi_x$.

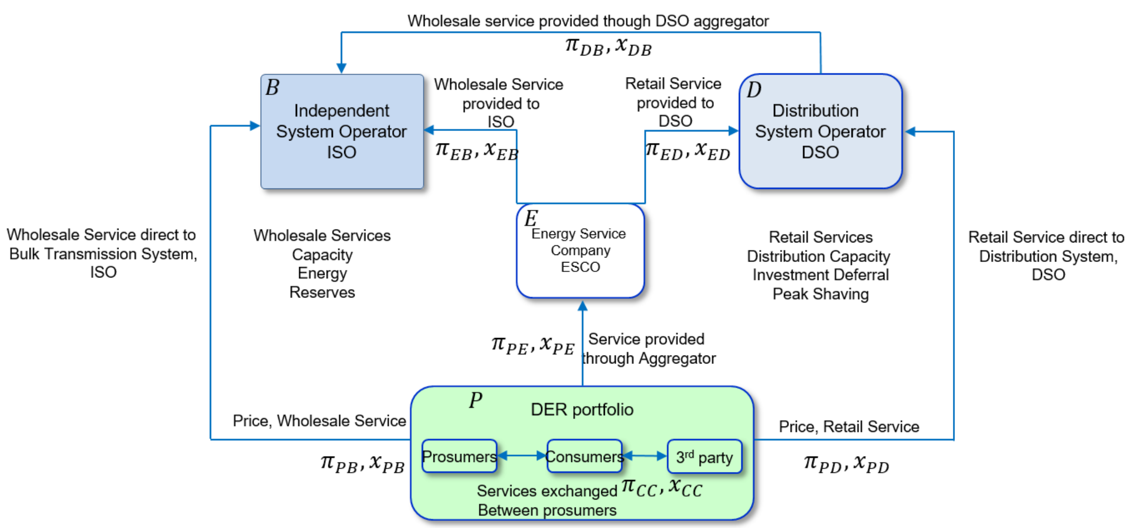


**Figure 12 – Schematic View of Market Actors, Market Rules, Services & Prices**

Figure 13 shows a diagram with some examples of market rules and service attributes. For example, this diagram shows that there are two markets: an ISO day-ahead and a DSO day-ahead market. There are three subsystems participating in these markets:

the DSO, the Aggregator and the Microgrid. Each of these subsystems are connected at specific nodes and contain specific resources. The type of grid services in these markets are: energy, spinning reserve, regulation, and demand response for the ISO market, and capacity deferral and demand response in the DSO market. Each of these services has a set of attributes that include: location, time, duration, frequency of need, quantity, maximum and minimum values, ramp rates, and price.

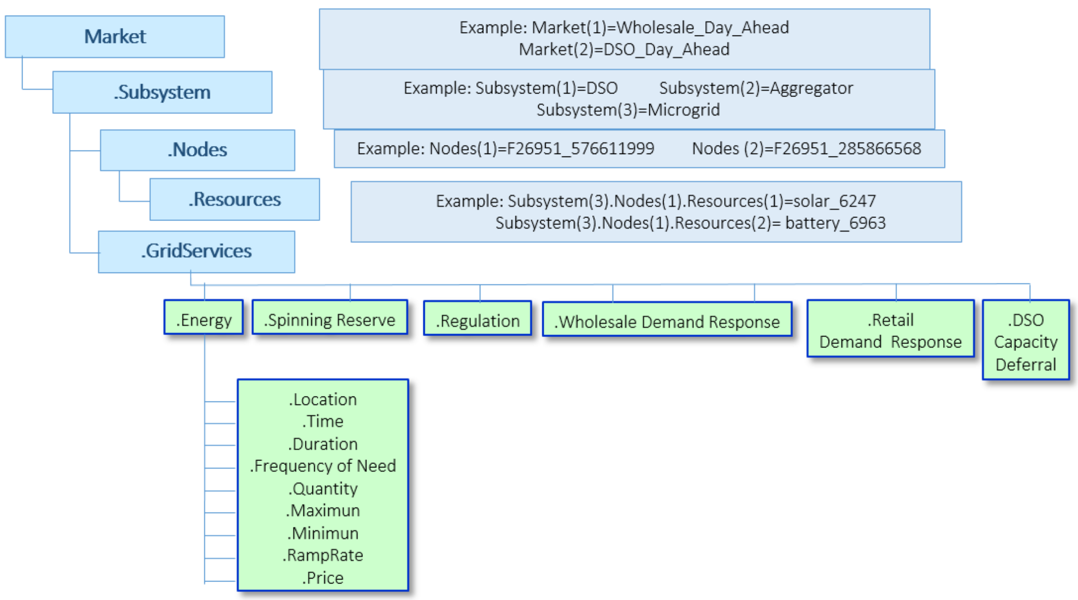


**Figure 13 – Example Diagram of Market Structure, Actors and Service Attributes**

### *3.3.3 Identification of Potential DER Services*

After the set of the different electric grid stakeholders (ISO, DSO, Energy Service Companies, Prosumers) has been identified, the third step in the prosumer-based BCA framework is to identify the DER services. The potential DER electric-grid services at the distribution and ISO levels have been adapted from [61] and are shown in Figure 14. DER services include: 1) Distribution System-Level Services: 1.1 Defer Distribution Projects, 1.2 Reliability (use DERs for fast reconnection and reserves to reduce demand when restoring customers during abnormal operations), 1.3 Resiliency (microgrid, set of DERs provides power to islanded customers when central power is not supplied, reducing duration of outages), 1.4 Improve Power Quality (voltage, transients, harmonics, etc.); 2) ISO Services: 2.1 Energy Market, 2.2 Reserves, 2.3 Ramping, 2.4 Frequency Regulation, 2.5 Smooth Intermittent Resource Output.

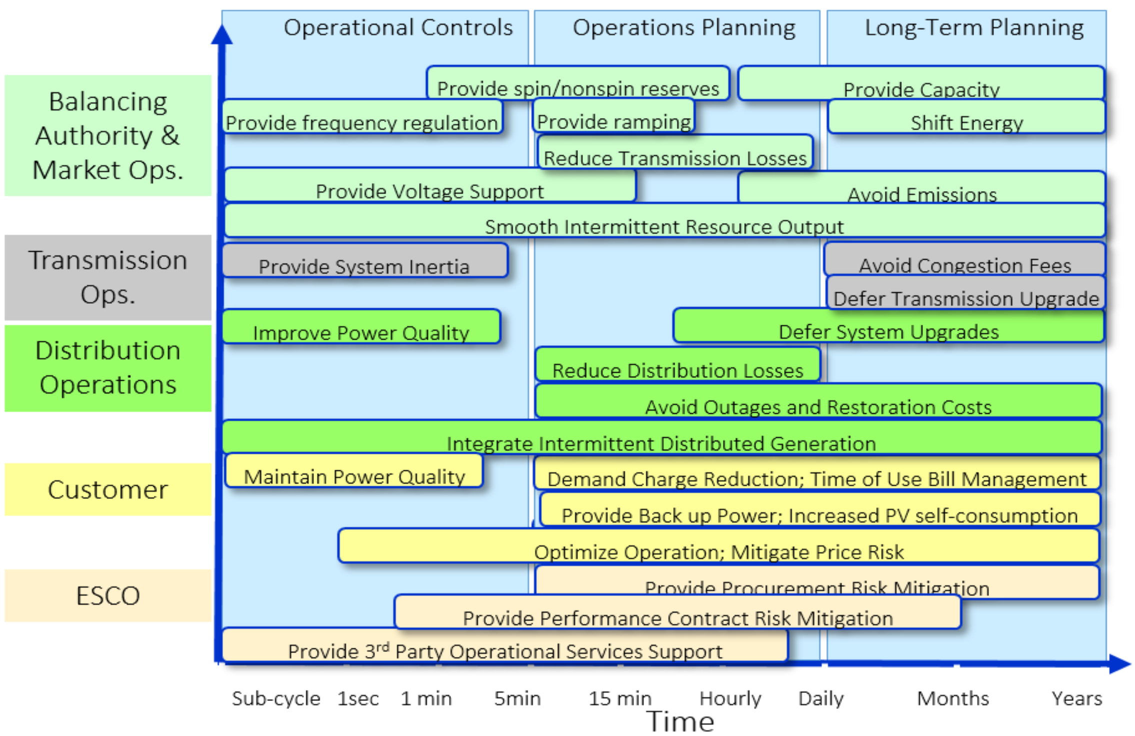


**Figure 14 – Potential Transmission, Distribution and Customer DER-Provided Services [61]**

### *3.3.4 Allocation of Benefit-Cost (Value) Categories*

The next step consists of classifying the impacts as benefits or costs and allocating the costs and benefits to different stakeholders within the power system. For example, some non-monetizable environmental impacts may benefit all society, but the customer who pays for the DERs is not compensated for the service provided. Figure 15 shows the Prosumer-

Based DER BCA Framework, major value impact categories, market actors (stakeholders) and sample classification.

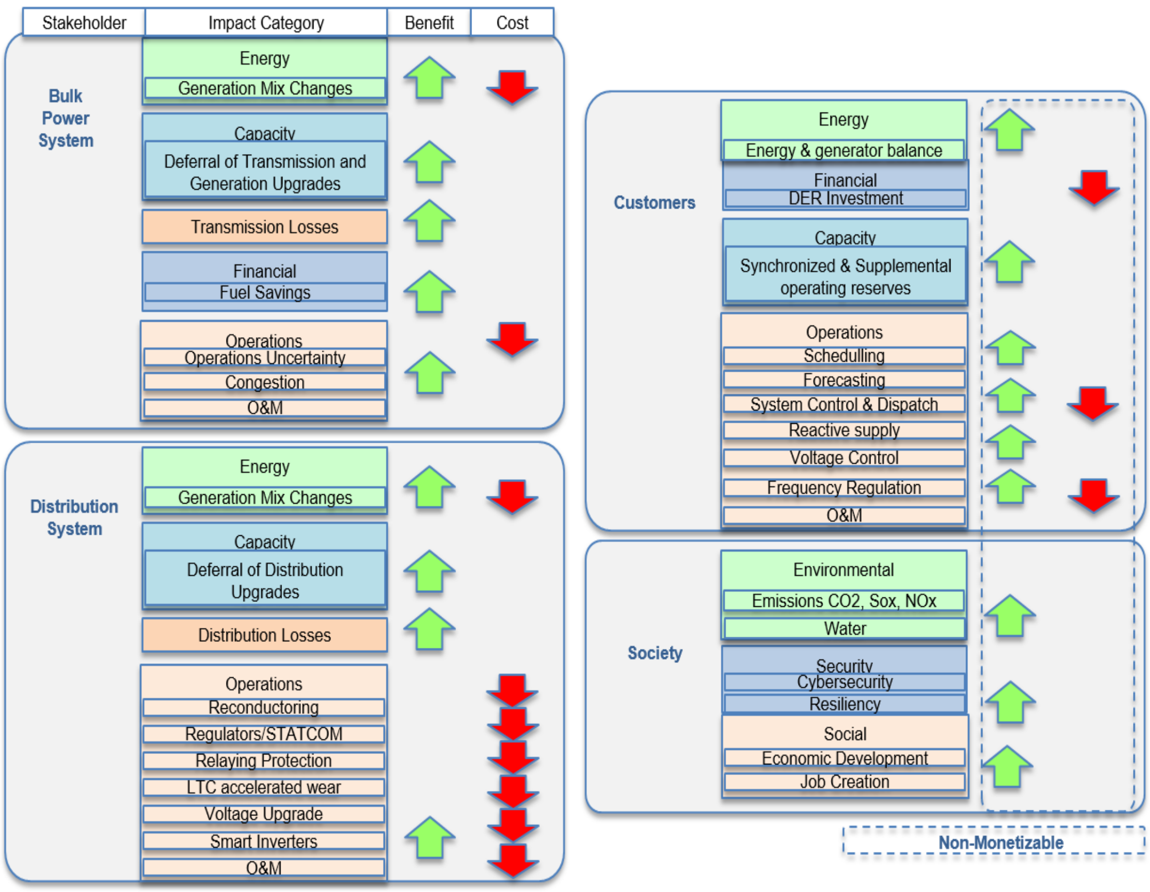


**Figure 15 – DER Benefit-Cost Framework and Impacts Categories**

### *3.3.5 Identification of Benefit-Cost Monetization Mechanism*

The fourth step is to identify how the benefits can be monetized so that all the net impacts are quantified in financial terms. Depending on market regulations several externalities are not included in the price of certain services. For example, in several regions there are no cost savings recognized to stakeholders that reduce emissions by producing power with renewable energy. Figure 16 from [2] shows that for an energy storage device there are several potential value streams. Some of them are not currently valued services in most deregulated markets such as: transmission upgrade deferral services, distribution voltage support services and reliability and resiliency. There are services currently valued in certain deregulated markets like energy time shifting, firm capacity, contingency spinning reserves, demand charge management, etc. There are some services on early adoption such as fast frequency response, ramping reserves, and transmission congestion relief. Several regions discuss the possibility of stacking different value categories to provide a more attractive value proposition for customers.

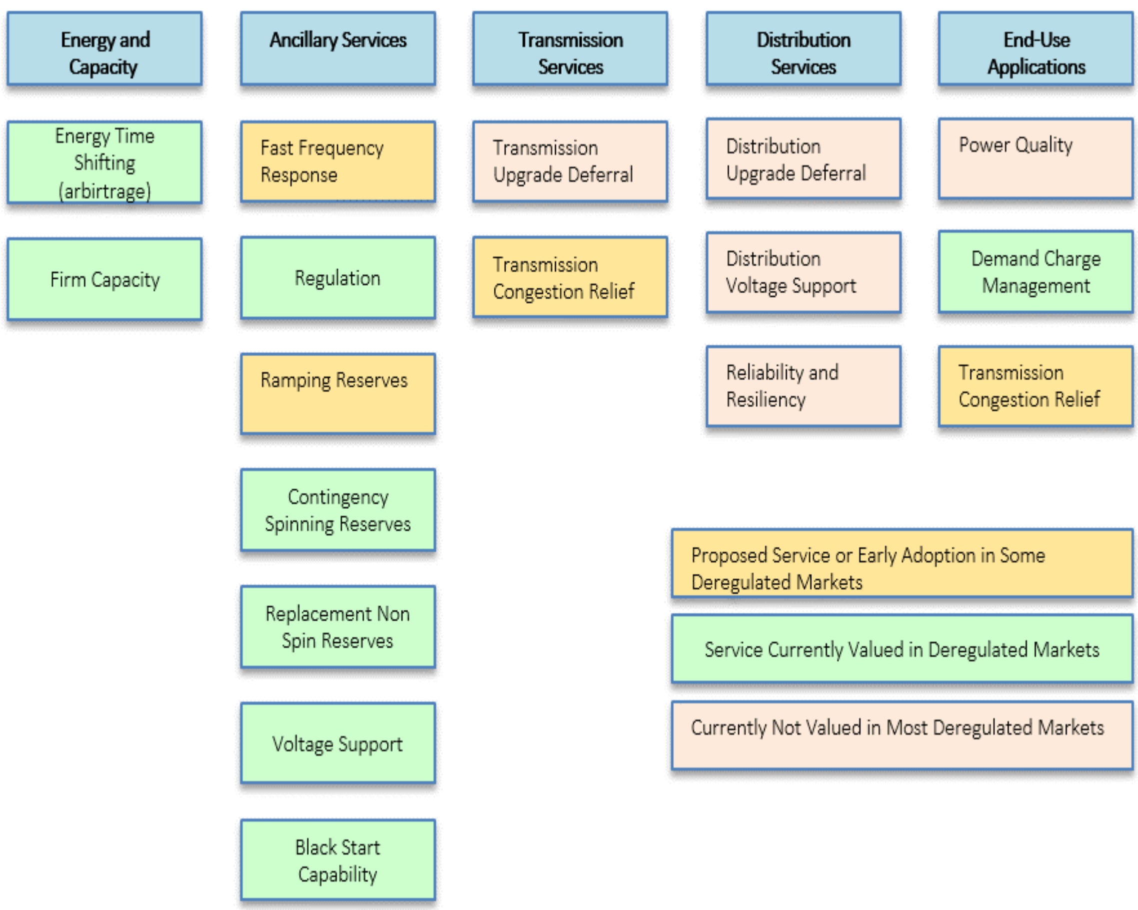


**Figure 16 – Potential Value Streams of Energy Storage [2]**

### 3.4 Locational Value Analysis of DER Portfolio Services

In order to value DER services, the modern power system planning methods described in [62] are used. The net present value (NPV) and economic value-added concept are adapted to account for the unique features of DERs. To determine the future cash flows for a specific DER project, a baseline case is defined. After adding the DERs, the economic optimization and time-series simulation should be conducted to estimate the impacts on the value categories. Based on the benefit-cost categories defined before, the set of future value flows is determined for the period of interest and then discounted at the appropriate discount rate. Equation (5) defines a portfolio's value as the sum of all the expected free cash flows ($FCF_i$) converted into today's dollars (discounted using the weighted average cost of capital, WACC). Free cash flows are defined as benefits or avoided costs including environmental impacts minus operational and investment costs, taking into consideration taxes, working capital and depreciation generated from the DER portfolio after paying DER integration costs, administrative costs, participant costs, etc.

$$NPV_P = \frac{FCF_1}{(1+WACC)^1} + \frac{FCF_2}{(1+WACC)^2} + \ldots + \frac{FCF_n}{(1+WACC)^n} \tag{5}$$

As can be observed in the above equation, the discount rate has been denoted as $WACC$ or weighted average cost of capital to stress an important fact: due to its paramount importance, the project's discount rate must not be arbitrarily assumed. Instead, it must be calculated following the principles of corporate finance. A high WACC implies much fewer projects will be deemed profitable, and thus not pursued. A low WACC implies the opposite. If inflated or deflated from its real value, all else being equal, the WACC will respectively either push the decision-makers to pursue less risky projects while overlooking value-add project opportunities (if inflated) or push the firm to pursue riskier projects that are less assured of value-add (if deflated). Choosing the best parameters possible is critical to establishing a WACC that will ensure the firm is generating the maximum amount of value with the projects it pursues and rejects.

The Weighted Average Cost of Capital ($WACC$): WACC can be estimated using Equations (6) (7):

$$WACC = \frac{D}{V}(1-t)r_D + \frac{E}{V}r_e \tag{6}$$

$$V = D + E \tag{7}$$

where $r_D$ is the cost of debt, $r_e$ is the cost of equity, $D$ is the market value of debt, $E$ is the market value of equity, $V$ is the market value of the firm and $t$ is the firm's (electric utility, aggregator, microgrid, commercial, industrial, home) marginal tax rate.

Cost of Equity ($r_e$): To calculate the cost of equity the Capital Asset Pricing Model (CAPM) was used [63] and is show in Equation (8):

$$r_e = r_f + \beta E(r_m - r_f) \tag{8}$$

where $r_f$ is the risk-free rate, $\beta$ is the sensitivity to market returns and $E(r_m - r_f)$ is the expected market risk premium.

Risk-Free Rate: To estimate the risk-free rate, long-term treasury bonds with maturity matching the maturity of the project should be considered. When calculating the WACC for the entire project, and the firm is an ongoing concern, the risk-free rate over the longest period available should be considered.

$\beta$ is the sensitivity to market returns and is estimated as the average value from comparable firms (firms that have their revenue coming from sales in the same market sectors). When these companies have different corporate structures, their betas need to be unlevered as indicated in Equation (9):

$$\beta_U = \frac{\beta_L}{1 + (1 - t) \times \frac{D}{E}} \tag{9}$$

where $\beta_L$ is the levered beta, and $\beta_U$ is the unlevered beta.

Cost of Debt ($r_D$): This represents the effective rate that a company pays on its current debt. When a company has several debt issues, short term and long term, the weighted average on the return of short-term ($YTM_A$) and long-term ($YTM_B$) debts needs to be estimated by computing the weighted average of Yield to Maturity (YTM)'s or $r_i$ of all debt issues. For the debt issues $i$ corresponding to bonds with $t_i$ periods, $CPN_i$ coupon payments, $M$ par value received at maturity, the following can be applied:

$$Price_{Issue\ i} = \frac{CPN_i}{r_i}\left(1 - \frac{1}{(1 + r_i)^{t_i}}\right) + \frac{M}{(1 + r_i)^{t_i}} \tag{10}$$

$$r_D = w_A YTM_A + w_B YTM_B \tag{11}$$

### *3.4.1 Distribution-Level Services*

Figure 17 shows the scope of DER portfolio impacts, which includes: 1) Avoided Distribution Capacity Infrastructure, 2) Avoided Generation Capacity Costs, 3) Avoided Energy Costs, 4) Avoided Emissions, and 5) Avoided Losses. Impacts associated with voltage support, avoided restoration and outage costs are not directly monetized in the market yet. Therefore, they have not been included in the analysis. However, it is recognized that as distribution markets evolve the need to value these services will become more apparent. The methodology presented could be extended to assess the value of those services as well.

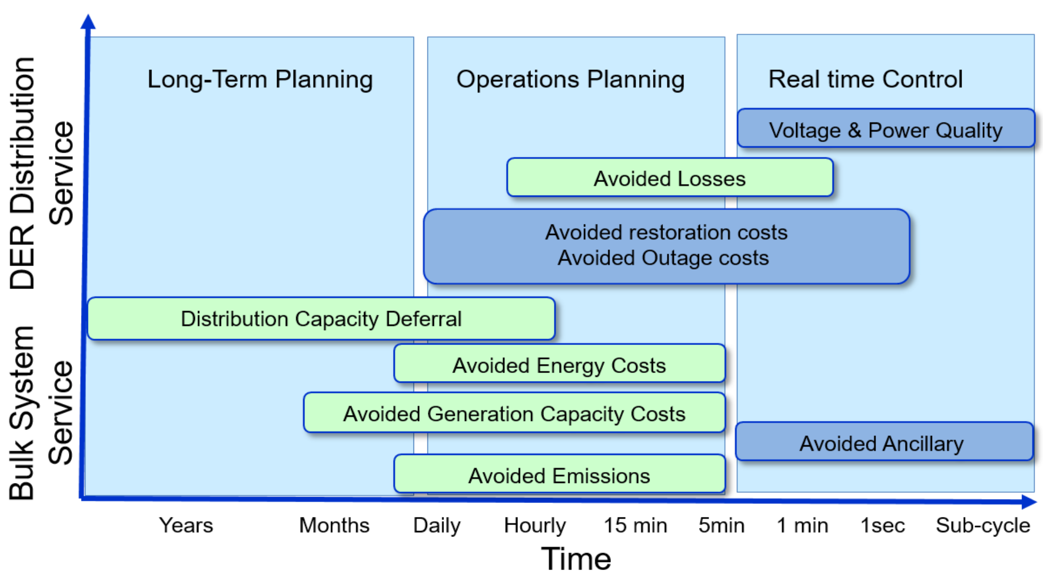


**Figure 17 – DER Wholesale and Distribution-Level Services**

### *3.4.2 Locational DER Net Present Value*

The method divides the DER valuation into: 1) investment optimization, and 2) optimal production costing (distribution-level economic optimization, which will be described in the next sections). The investment optimization takes the resulting annual operational cost $C_{P,y}$ as input. Suppose that there are $m$ mutually exclusive investments in DER portfolios ($P = 1,2, \dots m$). The portfolio with the highest net present value should be recommended. In a general sense, the following objective function needs to be maximized.

$$\max NPV_P = \sum_{y=0}^{n} (B_{P,y} - C_{P,y} - K_{P,y}) \left(\frac{1}{1+i}\right)^{y} \quad (12)$$

where, $NPV_P$ = Net Present Value of DER portfolio $P$; $B_{P,y}$ = Benefit/avoided cost (bulk system, distribution system) of DER portfolio $P$ in year $y$; $C_{P,y}$ = Operational cost (i.e. from scheduling) of DER portfolio $P$ in year $y$; $K_{P,y}$ = Investment of DER portfolio $P$ in year $y$; $i$ = Interest or discount rate (i.e. $WACC$); $n$ = Analysis period.

### *3.4.3 Benefit: Avoided Distribution Capacity Infrastructure*

This benefit represents the location-specific avoided distribution capacity infrastructure and is based on the CPUC LNBA final report [64]:

$$B_{ADCI_T} = \sum_{y=1}^{T} \left(K_{TD,y} \times \left(\frac{r-i}{1+r}\right)\left(\frac{(1+r)^N}{(1+r)^N-(1+i)^N}\right) \times RRScaler_y + \Delta O\&M\right) \left(\frac{1+i}{1+r}\right)^{y-1} \quad (13)$$

where $B_{ADCI_T}$ = deferral of traditional distribution ($TD$) investment for $T$ years, $K_{P,y}$= Direct capital cost of the investment $TD$ in year n; $RRScaler =$ Revenue requirement scaling factor, which represents cost impacts associated with taxes, administrative overhead and general plant and equipment; $\Delta O\&M$= Incremental annual cost of operation and maintenance; $i$ = Inflation; $r$ = Discount rate; $N$ =life of asset.

### *3.4.4 Benefit: Avoided Generation Capacity Costs*

This impact category represents reduced coincident system peak demand.

$$B_{ACC_{y+1}} = \sum_b \Delta PeakLoad_{b,d,y} \times AGCC_{Z,Y,b} \tag{14}$$

where: $b$ =ISO zone; $d$ =DSO zone, retail delivery or connection point; $y$ =Year; $\Delta PeakLoad_{b,d,y}(\Delta MW)$ = Portfolio's expected maximum demand reduction compared to baseline; $AGCC_{b,d,y}$ = Annual Avoided Generation Capacity Costs based on the forecast of capacity prices for the wholesale market.

### *3.4.5 Benefit: Avoided Energy*

Represents the avoided energy purchased at the Locational Marginal Price (LMP). The LMP includes three components: energy, congestion, and losses.

$$B_{AE_y} = \sum_b \sum_\tau \Delta Energy_{b,d,y} \times LMP_{b,d,y} \tag{15}$$

where, $\tau$ = period (e.g., year, season, month, and hour); $\Delta Energy_{b,d,y}(\Delta MWh)$ = difference in energy purchased at the connection point before and after the DER portfolio project implementation; $LMP_{b,d,y}(\$/KWh)$ = LMP price at distribution node *d*.

### 3.4.6 DER: Solar PV System Costs

Assuming an average PV power generated of $P_{G\_PV}$, the following economic analysis is considered for a 1000[W] PV system. The different parameters that affect the cost of PV modules like maintenance cost, area cost, power related balance of system (BOS), etc. and assumed values are shown in Table 2.

**Table 2 – Solar PV System Cost Parameters**

| Parameter | Symbol | Values |
| --- | --- | --- |
| Module Cost | $P_{mod}$ | \$2.00/$W_p$ |
| Power-Related BOS Cost | $P_{bos}$ | \$0.74/$W_p$ |
| Area-Related BOS Cost | $A_{bos}$ | \$82.00/$m^2$ |
| Installation Cost | $P_{ins}$ | \$2.43/$W_p$ |
| Module Efficiency | $\eta_{mod}$ | 13.5% |
| System Losses | $l_{sys}$ | 25% |
| Annual Insolation | $l$ | 1789 $kW.h/m^2$ |
| Interest Rate (APR) | $r$ | 3.625% |
| System Life | $n$ | 30yr |
| Avoided Electric Utility Electricity Cost | $C_{util}$ | \$0.113 |
| Marginal Tax Rate(Federal & State) | $t$ | 35% |
| Subsidy Rate | $f_{sdy}$ | 30% |

The installed PV system cost $[\$/\mathrm{m}^2]$ can be calculated as:

$$S = P_{G\_PV}\eta_{mod}(P_{mod} + P_{bos} + P_{ins}) + A_{bos} \tag{16}$$

The Annual payment on the PV system is:

$$P_a = S\left[\frac{r}{1-(1+r)^{-n}}\right] \tag{17}$$

On the other side, the annual energy production of the PV system can be calculated as follows:

$$E = l(\eta_{mod}(1 - l_{sys})) \tag{18}$$

The cost of energy is calculated as follows: the annual expense divided by annual energy production,

$$C = \frac{P_a}{E} \tag{19}$$

$$C = \frac{S}{E}\left[\frac{r}{1-(1+r)^{-n}}\right] \tag{20}$$

$$C = \frac{1000\eta_{mod}(P_{mod} + P_{bos} + P_{ins}) + A_{bos}}{l\eta_{mod}(1 - l_{sys})}\left[\frac{r}{1-(1+r)^{-n}}\right] \tag{21}$$

Finally, the payback period can be calculated as:

$$T = \frac{n(P_a)}{E(C_{util})} \tag{22}$$

If monthly payments are used, the equations are formulated as follows:

$$P_m = S\left[\frac{r}{1-(1+r)^{-n}}\right] \tag{23}$$

The Annual payment on the PV system is calculated as:

$$P_a = S\left[\frac{12r}{1-(1+r)^{-n}}\right] \tag{24}$$

Average monthly interest paid is calculated as:

$$P_i = P_m - \frac{S}{n} \tag{25}$$

The effective monthly payment is calculated as:

$$P_{m,eff} = P_m - t(P_i) \tag{26}$$

The effective annual payment is calculated as:

$$P_{a,eff} = 12(P_{m,eff}) \tag{27}$$

The effective cost of energy is:

$$C = \frac{P_{a,eff}}{E} \tag{28}$$

The effective payback period is:

$$T = \frac{n(P_{a,eff})}{EC_{util}} \tag{29}$$

**Table 3 – Residential PV Cost**

| Parameter | Variable | Values |
|---|---|---|
| Installed PV System Cost | $S$ | $779.95\ \$/m^2$ |
| Annual Payment on the PV System | $P_a$ | $43.073\ \$/m^2$ |
| Annual Energy Production of the PV System | $E$ | $181.14\ kWh/m^2$ |
| Cost of Energy | $C$ | $0.23\ \$/kWh$ |
| Payback Period | $T$ | $18.93\ yr$ |

**Table 4 –Residential PV Cost Estimate Using Monthly Payments**

| Parameter | Variable | Values |
|---|---|---|
| Monthly Payment | $P_m$ | $3.55\ \$/m^2$ |
| Annual Payment on the PV system | $P_a$ | $42.68\ \$/m^2$ |
| Average Monthly Interest Paid | $P_i$ | $1.39\ \$/m^2$ |
| Effective Monthly Payment | $P_{m,eff}$ | $3.07\$/m^2$ |
| Effective Annual Payment | $P_{a,eff}$ | $36.84\ \$/m^2$ |
| Effective Cost of Energy | $C$ | $0.203\ \$/kWh$ |
| Effective Payback Period | $T$ | $16.2\ yr$ |

### *3.4.7 DER Economic Value Added*

DER Economic Value Added (DEREVA) is proposed as a novel business impact and decision-making metric. It indicates the return of investment that a certain electric utility or service provider would expect from its invested capital (sum of contributed debt and equity) in a DER portfolio. It serves to compare DER investment alternatives. DEREVA is calculated as follows:

$$DEREVA = (\frac{NPV}{IC} - WACC) \times IC \tag{30}$$

Where $NPV$= Net Present Value of DER portfolio; $IC$ = Invested Capital in DER service (\$); $WACC$ = discount rate (%). $NPV$ considers net benefits minus costs resulting from the DER portfolio. Value will be created only if return on IC is greater than WACC.

## 3.5 Simulation Results

### *3.5.1 Test Case Details*

The framework has been applied to the realistic feeder Olin Barre obtained from the Open Modeling Framework. Table 5 shows the distribution case statistics. The case contains 484 distribution nodes and has been populated with 333 houses that contain ziploads and water heaters. This study involves the use of three software packages: 1) Open Modeling Framework (OMF), 2) GridLAB-D, and 3) MATLAB. The software is installed in a laptop machine with processor Intel CORE i7 2.6GHz, 16GB of RAM. The research will use public information available in the OMF, NYREV and DRP proceedings from NY and CA.

**Table 5 – Olin Barre Distribution System Case Elements Summary**

| | |
|---|---|
| Distribution Nodes: | 484 |
| Capacitor: | 1 |
| Overhead Lines: | 334 |
| Underground Lines: | 93 |
| Transformers: | 192 |
| Fuses: | 44 |
| Switches: | 12 |
| Houses: | 333 |
| ZIPloads: | 333 |
| Water heaters: | 233 |

### *3.5.2 Use Case: Distribution Capacity Deferral Service*

Figure 18 shows the yearly load forecast for total demand from the distribution case. In this case, it is assumed that electric distribution planning analysis has identified that a distribution substation transformer is projected to overload in year 2019 during winter peak demand conditions. The distribution substation transformer is projected to serve a peak demand of 1.096 MW, which exceeds this transformer's thermal capacity rating of 1 MW by 9.6%. Furthermore, it is projected that this overload may reach up to 15% by the year 2020 for winter peak demand conditions. The traditional capacity investment is $5M.

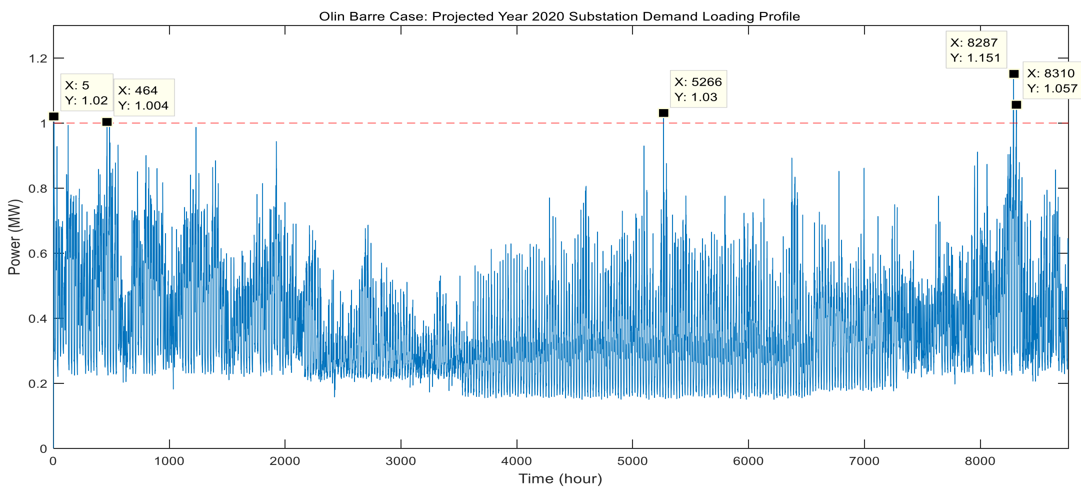


**Figure 18 – Distribution Capacity Need Identification by Load Forecasting**

### *3.5.3 Distribution Capacity Service Attributes and DER Scenario*

Based on this need identification, a set of distribution capacity service attributes are defined as shown in Table 6.

**Table 6 – Olin Barre Distribution System Case Device Summary**

| **DER Attributes to Procure** | **2019** | **2020** |
|---|---|---|
| Distribution Capacity Need (MW) | [0.96,0.65] | [0.2,0.04,0.3,0.5,1.51,0.4,0.57,0.44] |
| Months When Needed (1-12) | Nov. | Jan.-Dec. |
| Days When Needed (1-365) | [346,347] | [1,20,220,346,347] |
| Hours When Needed (1-8760) | [8287,8310] | [5,464,5266,8284,8287,8288,8310,8312] |
| Time When Needed (1-24) | [7,6] | [5,8,10,4,7,8,6,8] |
| Duration (hours/day) | 2 | 2 |
| Frequency of Need (days/month) | 2 | 2 |

A DER portfolio scenario is constructed that has a total nominal capacity contribution of 826.7 kW. The types of DER devices include solar PV, ES, EV charger, DR, and Energy Efficiency.

**Table 7 – DER Portfolio for Distribution Capacity Service Resource**

| DER Type | DER Penetration Assumption | Number of Objects | Capacity Contribution [kW] |
|---|---|---|---|
| Solar PV | 5 % of 931 Houses | 53 | 280.9 |
| Energy Storage (ES) | 22% of 53 PV Houses | 12 | 60.0 |
| EV Charger | 3% of 931 Houses | 32 | 240.0 |
| Demand Response (DR) | 10% of 233 Water Heaters | 23 | 230.0 |
| Energy Efficiency (EE) | 10% of 333 ZIPloads | 33 | 15.8 |
| Total | | 153 | 826.7 |

### *3.5.4 Quasi-Static Time-Series Simulation*

Figure 19 shows the results of the quasi-static time-series (QSTS) simulation. It is possible to see a reduction of forecasted peak demand.

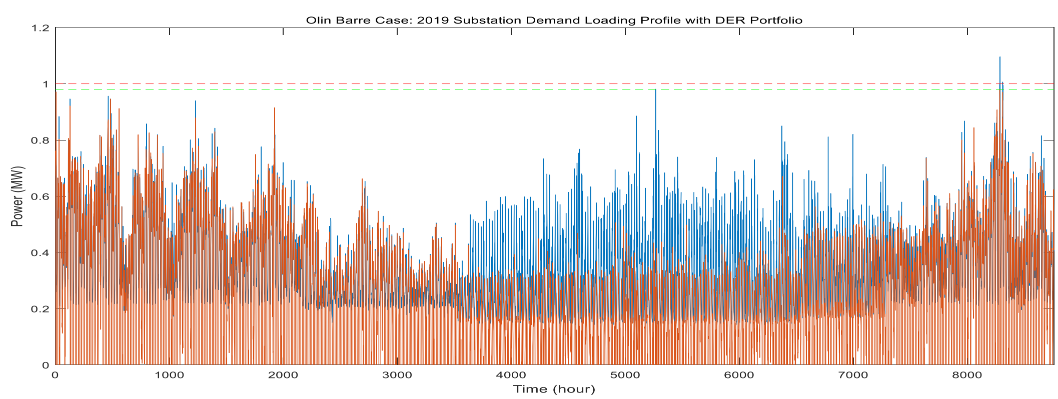


**Figure 19 – Distribution Capacity Need Mitigation by DER Portfolio**

A sample application of the framework [19] is shown in Figure 20. Using realistic feeder data, the change in value for different categories when DERs have been deployed is presented.

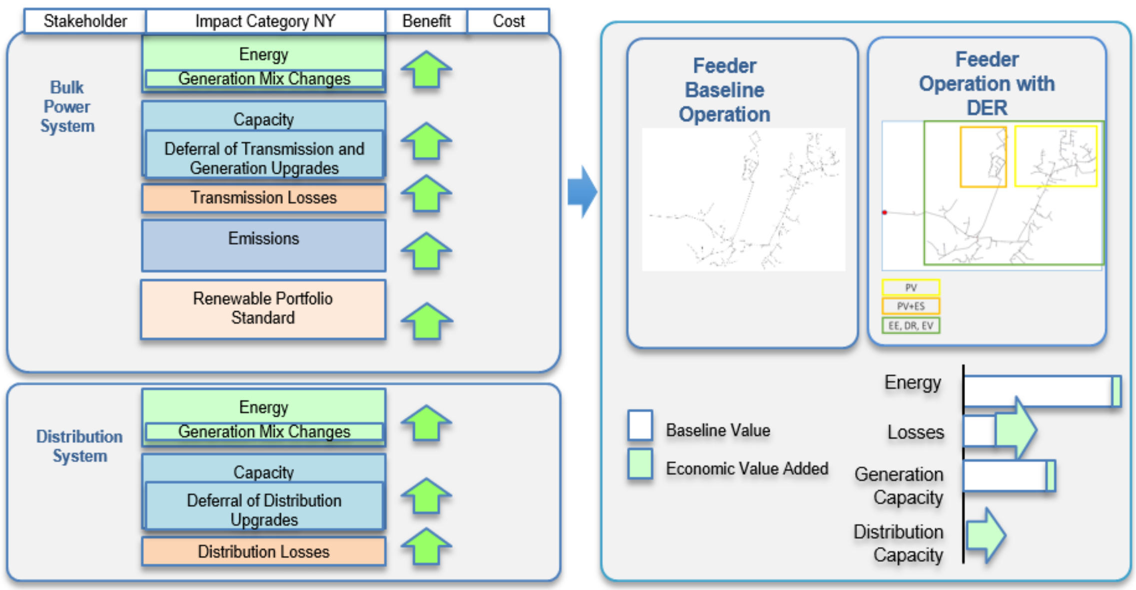


**Figure 20 – Sample DER Impacts Analysis OMF Olin Barre Model**

Figure 21 shows the locational temporal DER portfolio avoided costs. It is possible to see that the avoided cost value presents temporal variability. It is higher during the summer months when the avoided costs associated with energy, capacity and distribution capacity deferral are higher.

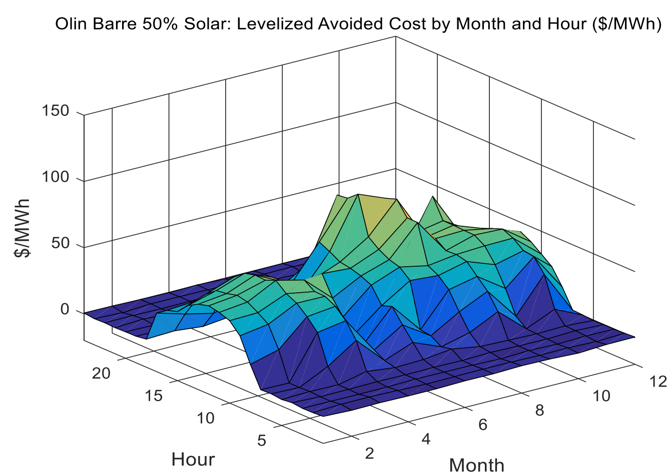


**Figure 21 – Locational Avoided Cost: Olin Barre 50% Solar**

### 3.6 Summary

This chapter has presented a Prosumer-based Benefit-Cost Framework for Locational Valuation of Distributed Energy Resources. The framework is based on the emerging concept of prosumers and a decentralized architecture. The method consists of several steps including: 1) The identification of the DER value chain segment; 2) The identification of market actors, market rules, and interrelations; 3) The identification of the potential service or value categories for DERs that will be exchanged; 4) The impacts are classified as benefits or costs, and the costs and benefits are allocated to different stakeholders within the power system; 5) The identification of how the benefits can be monetized so that all the net impacts are quantified in financial terms; 6) DER scenario generation; 7) Schedule of energy operations is obtained either from the DER scheduling or non-optimized schedule; 8) Then, a quasi-steady-state-time-series (QSTS) power flow simulation is run to compare the DER scenario with the baseline feeder operation; 9) Finally, the impacts on distribution and transmission and associated metrics are calculated. Simulation results are presented for the distribution capacity deferral use case when non-optimized schedules are considered. The framework provides a foundation to evaluate the net benefits of DERs including renewable energy.

# CHAPTER 4. DER-BASED ECONOMIC EMISSIONS OPTIMIZATION AT THE BULK TRANSMISSION SYSTEM LEVEL

## 4.1 Introduction

The following chapter is described in references [17], [65], and has largely been reproduced here. In order to quantify the impacts (avoided generation capacity costs and avoided emissions) that the aggregated coordination of flexible DER resources can provide at the bulk power system grid, a novel economic-emissions dispatch optimization model is proposed. The objective is to analyze the impact that aggregated coordination of DERs would have in the operational cost of the grid considering the effects of spinning reserve, PV power fluctuations, generation mix, emissions, and fuel costs. The optimization is applied to obtain the allocation of generation for different technologies such as coal, gas, nuclear, hydro, PV, flexible DERs in hourly resolution. A fraction of total load is made available as aggregate flexible load through DERs and is used to achieve demand reduction to reduce the costs of spinning reserves. The results are presented from the standpoint of two cost metrics: a) avoided emissions, and b) avoided generation capacity system costs. Simulations are conducted for three economic-emission dispatch use cases: a) without spinning reserves, b) with spinning reserves, 3) with different levels of aggregated DER flexibility and certain level of PV penetration. The results indicate that with used hypothetical costs, significant reduction of emissions and total costs occurs.

This chapter is organized into four sections. In section 4.2 a summary of models for quantification of benefits from DERs in power systems with renewable energy is presented. In section 4.3 the bulk power system economic-emissions optimization is presented. In section 4.4 simulation results are presented. Finally, section 4.5 presents a summary.

## 4.2 Models for Quantification of Benefits from DERs in Grid Scenarios with Renewable Energy Penetration

Sustainability objectives require integrating vast amounts of renewable energy into the electricity grid. However, renewable energy is spatially distributed, highly variable and less predictable. This imposes great challenges for power systems planning, operations and control including higher amounts of regulating and source following reserves [9]. There is an increasing need for a framework that integrates traditional and large numbers of distributed energy resources to respond to the variability in the power output of renewable energy resources due to weather fluctuations. The traditional way of serving loads and managing variability has required centralized coordination of expensive, not environmentally-friendly generation plants and regulating reserves. This method is not scalable as the levels of renewable energy increase and as the number of DERs and decision-makers increases to millions.

Higher amounts of renewable energy could elevate the volume of non-environmentally-friendly spinning reserves, which could counteract the economic benefits and the emission reductions achieved with renewables [66]. Spinning reserve, as described by North American Electric Reliability Corporation NERC [67], consists of the system-synchronized generation capacity that is not delivering power to loads (unloaded), and it is estimated in advance as a reserve generation capacity quantity that is additional to the amount needed to supply the estimated demand. The spinning reserve is usually available within 10 minutes to serve load. Spinning reserve is a critical factor in power system operation and planning because it is necessary to make the power system reliable.

Limited studies have been made to quantify the benefits from DERs in grid scenarios with renewable energy penetration, and consideration of aggregated DERs and its impacts on operational costs and reserves.

In reference [68], a quantification of the system benefits obtained by the application of flexible energy resources under high renewables penetration scenarios is described. A high-level description of the dispatch strategies is presented and detail models are not discussed.

Reference [69] describes that PV power fluctuations, hydro availability, generation mix, maintenance schedules, fuel costs, spinning reserve requirements, and geographical diversification are among the major factors that influence the economic and operational value of PV systems for large-scale applications. The study does not include an economic optimization model that considers generation and emissions constraints.

Reference [70] uses particle swarm optimization and presents an economic dispatch that includes transmission losses, PV generation and emission as constraints. Reference [71] presents a mixed-integer binary programming economic emissions dispatch model for power systems with thermal and PV generation. The studies do not include reserve considerations or the impact of aggregated DERs on the operational costs.

### 4.3 Bulk Power System-Level Economic-Emissions Optimization

In order to quantify the impacts (avoided generation capacity costs and avoided emissions) that the aggregated coordination of flexible DER resources can provide at the bulk power system grid, a novel economic-emissions dispatch optimization model is proposed.

#### *4.3.1 Generation Cost Modeling*

The input-output model of a generating unit that burns fossil fuel can be expressed as a function of its power output. The model is approximated by the polynomial in Equation (31):

$$C_i(P_{Gi}) = fp_iF_i = \acute{a}_i + \acute{b}_iP_{Gi} + \acute{d}_iP_{Gi}^2 \tag{31}$$

where $P_{Gi}$ = net power output (MW), $F_i$ = fuel input of *i*th generating unit (MBtu/hr)

$C_i$ = total operating cost ($/hr), $fp_i$ = equivalent fuel price of *i*th generating unit ($/MBtu)

#### *4.3.2 Peak Generation Cost Modeling*

The gas turbines are modeled as *n* power plants of equal capacity. Their respective costs are calculated as follows: first, the cost function of the aggregate gas generation is assumed to be:

$$C_{gas}(P_{Ggas}) = A + BP_{Ggas} + BP_{Ggas}{}^2 \tag{32}$$

This is composed of $n$ identical individual plants, each having a cost function.

$$C_{plant}(P_{Ggas}) = a + b(P_{Ggas}/n) + B(P_{Ggas}/n)^2 \tag{33}$$

So that the sum of all plant costs is:

$$C_{gas}(P_{Ggas}) = 10C_{plant}(P_{Ggas}) \tag{34}$$

*4.3.3 Emissions Cost Modeling*

The emission output of $SO_2$, $NO_X$, $CO_2$ from the generation unit is estimated by fuel consumption as shown in Equations (35)-(37):

$$EO_{SO_2,i}(P_{Gi}) = ef_{SO_2.i}F_i = \acute{\alpha}_{SO_2,i} + \acute{\beta}_{SO_2,i}P_{Gi} + \acute{\gamma}_{SO_2,i}P_{Gi}^2 \tag{35}$$

$$EO_{NO_X,i}(P_{Gi}) = \acute{\alpha}_{NO_X.i} + \acute{\beta}_{NO_X.i}P_{Gi} + \acute{\gamma}_{NO_X.i}P_{Gi}^2 \tag{36}$$

$$EO_{CO_2,i}(P_{Gi}) = \acute{\alpha}_{CO_2,i} + \acute{\beta}_{CO_2,i}P_{Gi} + \acute{\gamma}_{CO_2,i}P_{Gi}^2 \tag{37}$$

where $ef_i$ = emission factor (kg/MBtu or gallons/MBtu), $EO_i$ = emission output of $SO_2$, $NO_X$, and $CO_2$, (kg/hr)

*4.3.4 Load and Flexible DER Modeling*

The aggregated effect of heterogeneous types of loads is considered, including: a) non-flexible loads b) flexible loads: time-controllable loads such as EVs, thermostats and air conditioners; and c) switchable loads such as dishwashers and washing machines, etc. The total aggregated amount of flexible DERs is given by:

$$A_i(P_{Loadi}) = \gamma_i P_{Loadi} \tag{38}$$

where $P_{Loadi}$= total load at time $i$ (MW), $A_i$ = total aggregate flexible DERs at time $i$ (MW), $\gamma_i$= flexibility factor as percent of total load (%).

### 4.3.5 Economic Emissions Scheduling

For *N* generating units, the objective function can be expressed as follows:

$$Minimize\ J = \sum_{i=1}^{N}[C_i(P_{Gi}) + EO_i(P_{Gi})] \tag{39}$$

$$subject\ to\ \sum_{i=1}^{N} P_{Gi} = P_{Load} \tag{40}$$

$$P_{Gi}min \leq P_{Gi} \leq P_{Gi}max \tag{41}$$

where $P_{Gi}min, P_{Gi}max$ = minimum and maximum values for generator $P_{Gi}$ (MW). The Lagrangian function can be represented by:

$$\mathcal{L} = \sum_{i=1}^{N}[C_i(P_{Gi}) + EO_i(P_{Gi})] + \lambda(P_{Load} - \sum_{i=1}^{N} P_{Gi}) \tag{42}$$

where λ=Lagrange multiplier. The optimal conditions can be represented by

$$\frac{\partial\mathcal{L}}{\partial P_{Gi}} = \frac{\partial(C_i)}{\partial P_{Gi}} + \frac{\partial(EO_i)}{\partial P_{Gi}} - \lambda \tag{43}$$

$$\frac{\partial\mathcal{L}}{\partial\lambda} = P_{Load} - \sum_{i=1}^{N} P_{Gi} \tag{44}$$

$$\frac{\partial \mathcal{L}}{\partial P_{Gi}} = \frac{\partial \mathcal{L}}{\partial \lambda} = 0 \tag{45}$$

The procedure for obtaining the optimal economic-emissions dispatch iterates until a certain tolerance is met.

### *4.3.6 Reserves Scheduling*

It is assumed that whenever the demand exceeds 95 percent of the daily peak, an additional 10 percent spinning reserve is being deployed to manage unanticipated contingencies. The reserve scheduling policy assumes the use of flexible DERs:

$$Minimize\ \sum_{i=1}^{N}[C_i(P_{Gi\ Reserve})\ ] \tag{46}$$

$$subject\ to \sum_{i=1}^{N} P_{Gi\ Reserve} = P_{Reserve} - A_i(P_{Loadi}) \tag{47}$$

where $P_{Gi\ Reserve}$ = reserve unit power output (MW), $P_{Reserve}$ = total level of reserve required (MW), $A_i$ = total aggregate flexible DERs at time $i$ (MW).

## 4.4 Simulation Results

Simulation studies are conducted using a yearly load profile. First, in order to model the impact of the requirement for spinning reserve, the peaking generation (gas turbines) is modeled as ten power plants of equal capacity. Their respective costs are calculated by randomly generating polynomial coefficients added to the base case. The minimum power at which an active gas turbine can operate is also considered. First, the hourly distribution of the annual generation without concern for spinning reserve is calculated. Second, the spinning reserve is introduced into consideration. The generation is constrained to operate at 110 percent of the daily peak load whenever the load exceeds 95 percent of the daily peak. The optimization to be used in economic dispatch is formulated and applied to obtain the new hourly annual simulation.

Table 8 to Table 11 show the assumed values for: generation costs, $SO_2$ emissions costs, $NO_x$ emissions costs, and $CO_2$ emissions costs. In this study, hydro resources are assumed to be used at full capacity (2 percent of the peak capacity) throughout the year, and the ramp rates have been ignored.

**Table 8 – Values for Cost Curve of Generation Costs**

| Fuel Type | $\acute{a}_i$ | $\acute{b}_i$ | $\acute{d}_i$ |
|---|---|---|---|
| Coal | 12174.3501 | 97.4933 | 0.0000064998 |
| Gas | 16320.9607 | 129.9561 | 0.0000087594 |
| Nuclear | 2161.8944 | 16.4933 | 0.0000014615 |
| Hydro | - | - | - |
| PV (10 %) | 992924.9547 | 0.0000 | 0.0000000000 |

**Table 9 – Values for Cost Curve of $SO_2$ emissions**

| Fuel Type | $\acute{\alpha}_{SO_2,i}$ | $\acute{\beta}_{SO_2,i}$ | $\acute{\gamma}_{SO_2,i}$ |
|---|---|---|---|
| Coal | 1632.0885 | 13.0699 | 0.0000008714 |
| Gas | 0.8231 | 0.0000 | 0.0000000004 |
| Nuclear | 0.0000 | 0.0000 | 0.0000000004 |
| Hydro | 0.0000 | 0.0000 | 0.0000000000 |
| PV (10 %) | 0.0000 | 0.0000 | 0.0000000000 |

**Table 10 – Values for Cost Curve of $NO_x$ emissions**

| Fuel Type | $\acute{\alpha}_{NO_x.i}$ | $\acute{\beta}_{NO_x.i}$ | $\acute{\gamma}_{NO_x.i}$ |
|---|---|---|---|
| Coal | 739.0610 | 5.9185 | 0.0000003946 |
| Gas | 221.3974 | 1.7629 | 0.0000001188 |
| Nuclear | 0.0000 | 0.0000 | 0.0000000000 |
| Hydro | 0.0000 | 0.0000 | 0.0000000000 |
| PV (10 %) | 0.0000 | 0.0000 | 0.0000000000 |

**Table 11 – Values for Cost Curve of $CO_2$ emissions**

| Fuel Type | $\acute{\alpha}_{CO_2,i}$ | $\acute{\beta}_{CO_2,i}$ | $\acute{\gamma}_{CO_2,i}$ |
|---|---|---|---|
| Coal | 1632.0885 | 13.0699 | 0.0000008714 |
| Gas | 0.8231 | 0.0000 | 0.0000000004 |
| Nuclear | 0.0000 | 0.0000 | 0.0000000004 |
| Hydro | 0.0000 | 0.0000 | 0.0000000000 |
| PV (10 %) | 0.0000 | 0.0000 | 0.0000000000 |

The study uses the load data over one year. The modeled load represents both hourly and seasonal fluctuation. To show this fluctuation, the demand for the complete year is shown in Figure 22. The highest load peak occurs during summer.

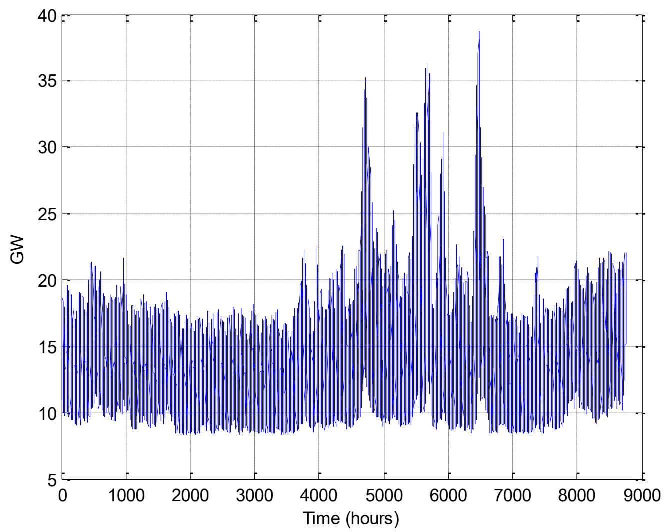


**Figure 22 – Yearly Modeled Load**

Ten percent of the year peak load capacity is assumed to be available in the form of PV in five cities. The hourly output of the aggregate PV systems in all the locations is calculated separately and then combined together using the System Advisor Model (SAM) as a PV simulator. Table 12 shows the PV capacity for the 10 percent PV penetration scenario.

Table 12 – PV Generation for Different Cities in Georgia

| PV Locations | PV Capacity % | Max GW | Total GW |
|---|---|---|---|
| Atlanta | 36.52 | 1.271 | 3.65940 |
| Augusta | 17.03 | 0.573 | |
| Columbus | 16.51 | 0.551 | |
| Savannah | 11.85 | 0.571 | |
| Athens | 10.15 | 0.346 | |
| Macon | 7.94 | 0.345 | |

The daily energy mix contribution from the different cities for day of peak consumption is shown in Figure 23.

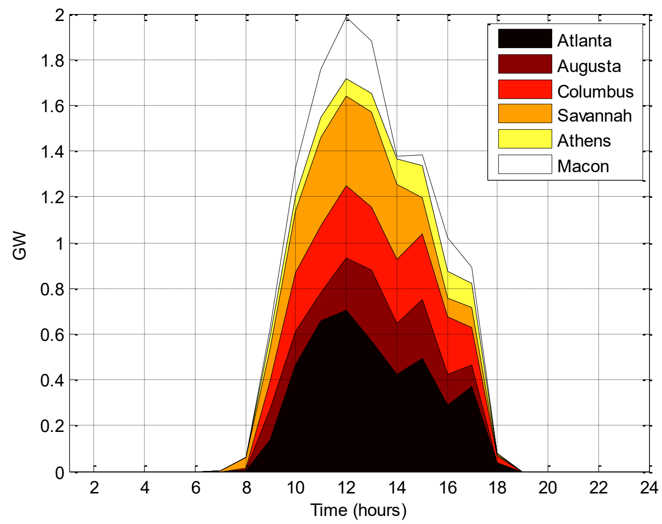


**Figure 23 – PV Energy Mix Contribution for the Day of Peak Consumption**

### *4.4.1 Use Case: Economic-Emissions Dispatch Without Spinning Reserve*

Considering the annual hourly load curve, the economic-emissions dispatch was calculated without considering spinning reserve. Table 13 shows the generation mix for the baseline case consisting of 45 GW of capacity distributed among the following technologies: coal, 10 gas plants, nuclear, hydro and PV.

**Table 13 – Baseline Case Generation Capacity Constraints**

| Type | Energy mix | Capacity limit in GW | |
|---|---|---|---|
| | | Min | Max |
| PV | 10% | 10% of peak | |
| Coal | 37% | 5.55 | 30.96 |
| Gas plants | 30% | 0.044 | 28.87 |
| Nuclear | 21% | 3.01 | 3.01 |
| Hydro | 2% | 0 | 0.77 |
| Spinning Reserve | - | If demand > 95% peak, reserve=10% peak | |

The daily energy mix and the spinning reserve for the first week of the year and the day of peak consumption is illustrated in Figure 24. It is possible to see that the majority of the energy mix is allocated to coal because of its lowest cost.

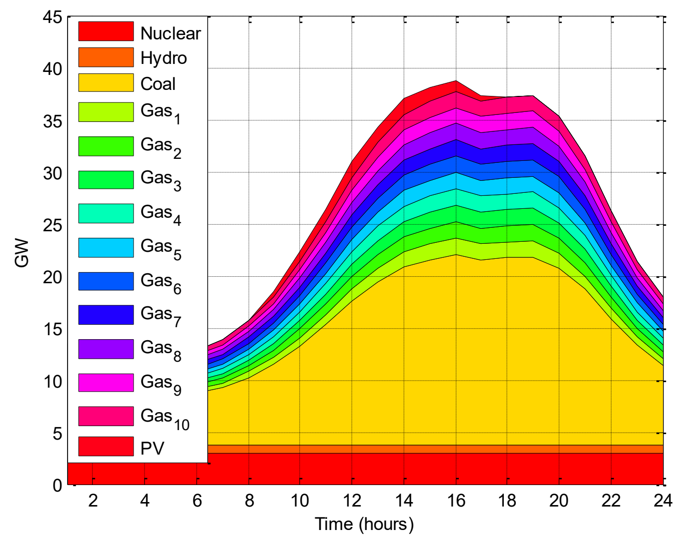


**Figure 24 – Energy Mix for the Day of Peak Consumption**

Assuming that the PV capacity is added to the energy mix of the State of Georgia, the economic emission dispatch is calculated for the new system consisting of all previously used generation sources, PV systems and the 10 generation plants.

**Table 14 – Annual Dispatch Values for Different Generation Technologies**

| | Aggregate Gas | Coal | Nuclear | Hydro | PV |
|---|---|---|---|---|---|
| Max [GW] | 8.870 | 26.2552 | 3.0100 | 0.77 | 3.36 |
| Min [GW] | 0.443 | 2.9430 | 3.0100 | 0 | 0 |
| Avg [GW] | 3.979 | 6.837 | 3.0100 | 0.770 | 0.631 |
| $25^{th}$ Percentile | - | 5.067 | 3.0100 | 0.770 | 0 |
| $50^{th}$ Percentile | - | 5.067 | 3.0100 | 0.770 | 0.1 |
| $75^{th}$ Percentile | - | 6.084 | 3.0100 | 0.770 | 1.27 |
| Annual Costs Billion $ | 18.640 | 27.04 | 8.0003 | 0 | 2.097 |
| Total Cost [Billions $] | | | | 55.7773 | |

Table 14 shows that the annual total cost is 55.7773 billion dollars. The major portion of the costs are allocated coal plants. On the other side, Table 15 shows that the total annual emissions when no spinning reserve is considered are 859.6 Megatons.

**Table 15 – Annual Emissions for Different Generation Technologies**

| [Megatons] | Coal | T. Gas | Nuclear | Hydro | Total |
|---|---|---|---|---|---|
| $SO_2$ | 3.569 | 0.0007 | 0 | 0 | 3.5697 |
| $NO_X$ | 1.1656 | 0.1998 | 0 | 0 | 1.3654 |
| $CO_2$ | 697.45 | 154.40 | 2.8225 | 0 | 854.67 |
| Total | 702.18 | 154.60 | 2.8225 | 0 | 859.60 |

### *4.4.2 Use Case: Economic-Emissions Dispatch Considering Spinning Reserve*

In this case it is assumed that whenever the demand exceeds 95 percent of the daily peak, an additional 10 percent spinning reserve is being deployed to manage unanticipated contingencies. Figure 25 shows the peak day energy mix and the spinning reserve.

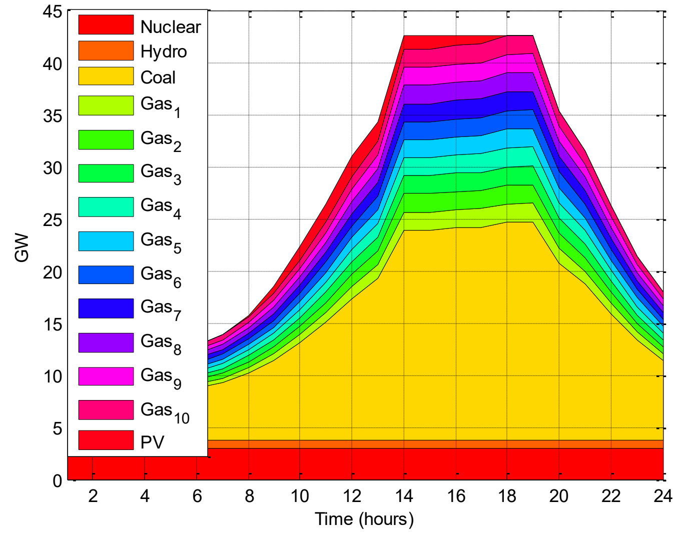


**Figure 25 – Energy Mix for the Day of Peak Consumption**

Table 16 shows that the annual total cost is 58.89 billion dollars. On the other side, Table 17 shows that the total annual emissions is 888.44 Megatons. Both quantities have increased due to the consideration of spinning reserves. The main result is that the variability of PV output increases the cost of operation because it requires the ramping of the gas generators.

**Table 16 – Annual Dispatch Values for Different Generation Technologies**

| | Aggregate Gas | Coal | Nuclear | Hydro | PV |
|---|---|---|---|---|---|
| Max [GW] | 8.870 | 28.2552 | 3.0100 | 0.77 | 3.36 |
| Min [GW] | 0.443 | 3.7630 | 3.0100 | 0 | 0 |
| Avg [GW] | 3.979 | 6.937 | 3.0100 | 0.77 | 0.631 |
| 25th Percentile | - | 5.067 | 3.0100 | 0.770 | 0 |
| 50th Percentile | - | 5.067 | 3.0100 | 0.770 | 0.1 |
| 75th Percentile | - | 6.324 | 3.0100 | 0.770 | 1.27 |
| Annual Costs Billion $ | 19.760 | 29.04 | 8.0003 | 0 | 2.097 |
| | | | Total Cost [Billions $] | | 58.8973 |

**Table 17 – Annual Emissions for Different Generation Technologies**

| [Megatons] | Coal | Gas | Nuclear | Hydro | Total |
|---|---|---|---|---|---|
| $SO_2$ | 4.4932 | 0.0007 | 0 | 0 | 4.494 |
| $NO_X$ | 2.0347 | 0.2277 | 0 | 0 | 2.2624 |
| $CO_2$ | 725.45 | 153.40 | 2.8225 | 0 | 881.68 |
| Total | 731.98 | 153.63 | 2.822 | 0 | 888.44 |

#### *4.4.3 Use Case: Economic-Emissions Dispatch Considering Aggregated DER Flexibility*

A simulation study is conducted in MATLAB with the purpose of quantifying the benefits that the coordination of flexible DER resources can provide to the grid. One of the main barriers for renewable energy integration identified in [68] is related to the ability of non-renewable generation to provide sufficient reserves for the power system. Since renewable sources are typically operated at maximum power output, they cannot provide reserves to the grid. Therefore, the objective is to analyze the impact that aggregated coordination of DERs would have on the operational cost of the grid considering the effects of spinning reserve, PV power fluctuations, generation mix, emissions, and fuel costs. Flexibility is defined as the capacity of responsive loads to provide energy services to the grid while maintaining the users' same level of service. The study uses the load data for the State of Georgia over one year. First, generation hypothetical costs are modeled. Second, load is modeled as flexible and non-flexible load. Ten percent of the year peak load capacity is assumed to be available in the form of PV in five locations in Georgia. The hourly output data of the aggregate PV systems in all the locations is obtained using NREL's System Advisory Model. Then, the economic, emissions dispatch optimization is formulated and applied to obtain the allocation of generation for different technologies such as: coal, gas, nuclear, hydro and PV in hourly resolution. A fraction of total load is made available as aggregate flexible load and is used to achieve load shifting to reduce the costs of spinning reserves or to accommodate excess renewable energy when it needs to be curtailed. Spinning reserve was considered to be deployed whenever the demand exceeded 95 percent of daily peak load forecast. The results are presented from the standpoint of two cost metrics: a) avoided emissions, and b) avoided energy costs. Simulations are conducted for different levels of DER flexibility for a certain level of PV penetration. The results indicate that with current hypothetical costs, significant reduction of emissions and total costs occurs.

The daily energy operation of PV, gas turbines and the spinning reserve for day of peak consumption is illustrated in Figure 26 for different flexibility factor scenarios. As the level of DERs increases, more thermal generation is displaced by flexible DERs.

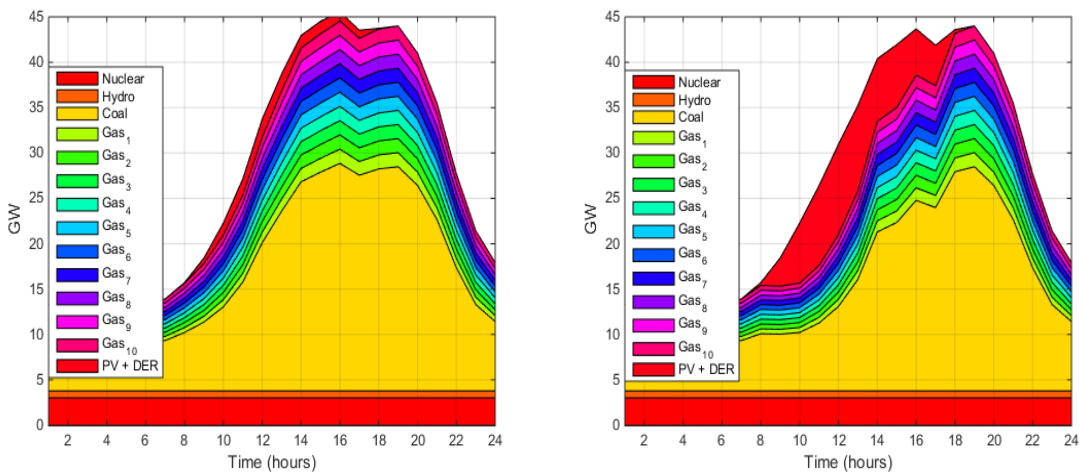


**Figure 26 – Generation Mix for the Day of Peak Consumption Considering Flexibility Factors of: a) 10% b) 30%**

Table 18 shows that the total annual cost for the base case (10 percent penetration) is $58.89 billion. On the other side, it shows that the total annual emissions is 888.44 megatons for the base case.

**Table 18 – Total Annual Output for Different Generation Technologies**

| | Gas | Coal | Nuclear | Hydro | PV |
|---|---|---|---|---|---|
| Max [GW] | 28.870 | 28.255 | 3.0100 | 0.77 | 3.36 |
| Min [GW] | 0.443 | 3.763 | 3.0100 | 0 | 0 |
| Avg [GW] | 3.979 | 6.937 | 3.0100 | 0.77 | 0.63 |
| Annual Costs Billion $ | 19.760 | 29.040 | 8.0003 | 0 | 2.09 |
| | | | Total Cost [Billions $] | 58.8973 | |
| | **Gas** | **Coal** | **Nuclear** | **Hydro** | **Total** |
| $SO_2$ | 0.0007 | 4.4932 | 0 | 0 | 4.494 |
| $NO_X$ | 0.2277 | 2.0347 | 0 | 0 | 2.262 |
| $CO_2$ | 153.40 | 725.45 | 2.8225 | 0 | 881.6 |
| Total Megatons | 153.63 | 731.98 | 2.822 | 0 | 888.4 |

Table 19 shows the results for different scenarios of DER coordination. Flexible loads scenarios are simulated using flexibility factors of 10 percent, 20 percent and 30 percent. The results indicate that under the 10 percent case, the cost of energy operations is reduced by about $272 million and emissions by about 16 megatons. This gives a DEREVA of $0.44 million. Other results show incremental benefits from coordinating additional DER flexibility

**Table 19 – Estimated Benefits for Different Levels of DER Coordination**

| PV Penetration % | Flexibility Factor % | Emissions Megatons | Annual Cost Million $ |
|---|---|---|---|
| 10% | Baseline | -- | -- |
| | 10% | -16.5 | -272 |
| | 20% | -11.2 | -530 |
| | 30% | -5.70 | -776 |

### 4.5 Summary

This chapter presents a model that consists of several stages that describe generation costs, emission costs, the expected load (including flexibility factors for flexible loads), and renewable generation. The main goal of the proposed model is the optimization of two objective functions: economic and emissions costs of generation and quantification of aggregated DER impact on reserve requirements. The study considers the effects of spinning reserve, PV power fluctuations, generation mix, fuel costs, and assesses the possible impact that penetration of photovoltaic generation and aggregated DERs would have in the operational cost of the grid. These issues are addressed by analyzing the modeled year load data for the State of Georgia. First, in order to model and assess the impact of the requirement for spinning reserve, the peaking generation (gas turbines) is modeled as ten power plants of equal capacity. Their respective costs are calculated by randomly generating polynomial coefficients added to the base case, and the minimum power at which an active gas turbine can operate is also considered. Then, the hourly distribution of the annual generation without concern for spinning reserve is calculated. Second, the spinning reserve is introduced into consideration. The generation is constrained to operate at 110 percent of the daily peak load whenever the load exceeds 95 percent of the daily peak. The optimization to be used in economic/security dispatch is formulated and applied to obtain the new hourly annual simulation. The results generated are compared and contrasted with the data obtained without spinning reserve consideration. Lastly, in order to offer economic indicators to possible investors, the results are analyzed by the DER Economic Value-Added method. The simulation results show that as the factor of DER flexibility increases, total costs and total emissions are reduced.

# CHAPTER 5. DER PORTFOLIO ECONOMIC OPTIMIZATION AT THE DISTRIBUTION LEVEL

## 5.1 Introduction

This chapter presents a DER portfolio economic schedule optimization at the distribution level which is the fourth step in the valuation methodology. The optimization takes into consideration a portfolio of DER devices that include: flexible loads, distributed generators, energy storage devices, and solar PV generators. The objective of the prosumer is to optimally operate the portfolio of DERs over a day-ahead time horizon while taking into consideration: 1) market constraints such as: price signals and specific DER market avoided costs such as avoided energy costs, avoided capacity costs, avoided emissions costs, avoided renewable portfolio standard costs, and avoided ancillary services costs, 2) system level constraints such as: power balance, reserve constraints and 3) device constraints such as: a) flexible load minimum and maximum rated power, maximum ramp up and down rates, minimum and maximum comfort constraints and energy conservation constraint; b) storage constraints: minimum and maximum capacity, maximum charge and discharge, and energy conservation constraint. Simulation results are presented for a use case where a prosumer has a portfolio of DERs composed by thermostatically-related flexible loads, energy storage devices, and solar PV generators. The virtual power plant is exposed to the local electric utility day-ahead prices at one-hour granularity. The simulation results show that the optimization is able to achieve peak reduction and load leveling for the temperature related load while considering all the mentioned constraints. In addition, the DER portfolio optimization enables a decreased consumption of the HVAC power during periods of high price, shifting operation to hours before price peak occurs in order to reduce the total cost. The simulation also shows that the total operational costs are reduced as the comfort level factor is increased. A second use case is presented, with a distribution network populated with energy storage devices, solar devices, flexible demand devices and a distributed generator. In this case, it is assumed that whenever the load is greater than 95 percent of the expected load, spinning reserves, non-spinning reserves and operating reserve services are required from the generator. The goal of the optimization model is to determine the minimum cost schedule of operations for the DER portfolio. Results are presented for avoided system costs, showing that significant benefits are obtained with DER optimization.

This chapter is organized in four sections. In section 5.2 a summary on distribution systems with penetrations of DERs is presented. Then, the proposed DER portfolio economic dispatch optimization at the distribution level is described in section 5.3. Section 5.4 presents simulation results. Finally, a summary is presented in section 5.5.

## 5.2 Optimization of DER Operations in Distribution Systems

Local jurisdictions are transforming their electric grid planning, operations and business models into a more sustainable, integrated, customer-oriented model where distributed energy resources (DERs) including renewable generation, demand response, electric vehicles and energy storage become crucial instruments in the operation of the interconnected grid [10]. Recent reports have estimated that DERs such as energy storage and flexible demand offer an opportunity to increase system efficiency [68]. However, it is still a major challenge to plan and coordinate the operation of millions of different devices and subsystems in order to achieve the grid objectives of ultra-reliability, economic optimization and sustainability [72].

Several optimization models have been proposed and their major gaps are described below. Reference [73] proposes a linear programming optimization to solve the scheduling of DERs. The optimization has two objective functions: peak shaving and economic operation. The study includes energy storage but does not include demand response, generators or PV systems. Reference [74] proposes a service aggregator for PV and energy storage systems that uses a model predictive control algorithm for DER optimization. The optimization is modeled as mixed integer linear programming and uses relaxation methods in the algorithm. The model does not include generators, demand response or system avoided costs in the analysis.

Reference [75] describes an optimal scheduling model for demand response at the home energy management system level. The model uses mixed integer linear programming to minimize the electricity expenditure of the consumer. Another optimization of DERs at the home level is presented in [34] where detailed models of thermostatically-related loads, energy storage and appliances are optimized in a dynamic price environment.

Reference [76] proposes a distributed energy optimization at the microgid-level using transactive control and a heuristic strategy. The paper includes additional DERs such as distributed generation, loads and energy storage. It does not include system avoided costs in the objective function or demand response modeling.

Reference [77] describes adaptive control scheme to optimize the operation of DERs without knowledge of a model of the distribution network. It uses this approach to expose services to the transmission level. The model does not include specific models of DERs or market constraints.

Reference [78] proposes a control and bidding strategy for virtual power plants. The model uses a stochastic bi-level optimization problem. It does not include explicit modeling of energy storage, demand response or avoided costs in the objective function. Similarly, [79] uses a stochastic bi-level approach to address the optimal offering strategy of a virtual power plant. Given that the problem is solved for the commercial virtual power plant perspective, the problem does not consider system avoided costs in the objective function.

In summary, most of the studies have focused on specific use cases of the DER scheduling problem either at the home, microgrid, virtual power plant or aggregator level. However, there has been a lack of focus on the simultaneous effect that a portfolio of devices such as energy storage, solar PV, distributed generation, and demand response will have while taking into consideration market, system and device-level constraints. Also, no consideration of system avoided costs (such as avoided energy, avoided capacity, avoided ancillary services, avoided renewable portfolio standard) has been included in the objective function.

## 5.3 DER Portfolio Economic Optimization

This section presents the problem formulation for the DER energy scheduling problem. The generator model is largely based on [35], without the inclusion of quadratic costs, the demand response model is based on [80], the energy storage is based on [81].

### *5.3.1 Sets and Indices*

Consider a DER portfolio $P$ with the following DERs:

$W$ set of solar photovoltaic devices indexed by $w$;

$Q$ set of energy efficient devices indexed by $q$;

$Dr$ set of flexible load devices indexed by $dr$;

$S$ set of energy storage devices indexed by $s$;

$G$ set of generator devices indexed by $g$;

$D$ set of demands indexed by $d$;

$\tau$ set of time periods indexed by $t \in \tau = \{1, \dots T\}$

### 5.3.2 *Generator Parameters*

The following parameters are defined for each generator device:

$\underline{P_g}$ Minimum power output of generator $g$, [kW]

$\overline{P_g}$ Maximum power output of generator $g$, [kW]

$\overline{P_g^u}$ Maximum ramp-up rate of generator $g$, [kW/h]

$\overline{P_g^d}$ Maximum ramp-down rate of generator $g$, [kW/h]

$SD_g$ Shutdown capability of generator $g$, [kW]

$SU_g$ Startup capability of generator $g$, [kW]

$T_g^{CS}$ Cold startup time of generator $g$, [h]

$TD_g$ Minimum downtime of generator $g$, [h]

$TU_g$ Maximum uptime of generator $g$, [h]

$C_g^{CS}$ Cold startup cost of generator $g$, [$]

$C_g^{HS}$ Hot startup cost of generator $g$, [$]

$C_g^{SD}$ Shutdown cost of generator $g$, [$]

$C_g^{LV}$ Linear cost of generator $g$, [$/kW]

$C_g^{NL}$ No-load cost of generator $g$, [$]

$C_g^{R}$ Reserve cost of generator $g$, [$/kW]

### *5.3.3 Energy Storage Parameters*

The following parameters are defined for each energy storage device:

$E_s^0$ Initial energy (beginning day ahead) in storage $s$, [kW·h]

$E_s^F$ Final energy (end day ahead) in storage $s$, [kW·h]

$\underline{E_s}$ Minimum energy in storage $s$, [kW·h]

$\overline{E_s}$ Maximum energy in storage $s$, [kW·h]

$\overline{P_s^{S+}}$ Maximum charge rate of storage $s$, [kW/h]

$\overline{P_s^{S-}}$ Maximum discharge rate of storage $s$, [kW/h]

$\eta_s^+$ Charge efficiency of storage $s$

$\eta_s^-$ Discharge efficiency of storage $s$

$C_s^{S-}(\cdot)$ Operational cost for discharging storage device $s$, [$/kW]

$C_s^{S+}(\cdot)$ Operational cost for charging storage device $s$, [$/kW]

$C_s^R$ Reserve cost of storage $s$, [$/kW]

### 5.3.4 *Line Parameters*

$\overline{F_{ij}^{S-}}$ Active power flow limit of line $ij$, [kW]

### 5.3.5 *Reserve Parameters*

$\tilde{R}_t^{SR}$ System Reserve requirement for spinning reserve service, [kW]

$\tilde{R}_t^{NSR}$ System Reserve requirement for non-spinning reserve service, [kW]

$\tilde{R}_t^{OR}$ System Reserve requirement for operating reserve service, [kW]

### 5.3.6 *Flexible Load Parameters*

The following parameters are defined for each generator device:

$\underline{P_{dr}}$ Minimum power of flexible load device $dr$, [kW]

$\overline{P_{dr}}$ Maximum power of flexible load device $dr$, [kW]

$\overline{P_{dr}^{D+}}$ Maximum ramp-up rate of flexible load device $dr$, [kW/h]

$\overline{P_{dr}^{D-}}$ Maximum ramp-down rate of flexible load device $dr$, [kW/h]

$\eta_{dr}^{-}$ Constant associated with reducing flexible load $dr$

$\eta_{dr}^{+}$ Constant associated with increasing flexible load $dr$

$C_{dr,t}^{D-}(\cdot)$ Operational cost of flexible load decrease for device $dr$ at time $t$, [$/kW]

$C_{dr,t}^{D+}(\cdot)$ Operational cost of flexible load increase for device $dr$ at time $t$, [$/kW]

$\tau_{dr}^{F}$ Set of time sub-periods during which the flexible load is flexible

### *5.3.7 Demand Parameters*

The following parameters are defined for each generator device:

$\tilde{P}_{d,t}^{D}$ Demand $d$ forecast in period $t$, [kW]

### *5.3.8 Market Price Parameters*

$\lambda_t$ Energy price forecast at time $t$, at interchange node (i.e. locational based marginal price, LBMP, at substation node, ISO zone, or granularity available) [$/ kW·h];

$\lambda_t^{SR}$ Spinning reserve price forecast at time $t$, at interchange node (i.e. locational based marginal price, LBMP, at substation node, ISO zone, or granularity available) [$/ kW·h]

$\lambda_t^{NSR}$ Spinning reserve price forecast at time $t$, at interchange node (i.e. locational based marginal price, LBMP, at substation node, ISO zone, or granularity available) [$/ kW·h];

$\lambda_t^{OR}$ Operating reserve price forecast at time $t$, at interchange node (i.e. locational based marginal price, LBMP, at substation node, ISO zone, or granularity available) [$/ kW·h];

$\pi_t$ System energy avoided cost forecast at time $t$, at interchange node (i.e. locational based marginal price, LBMP, at substation node, ISO zone, or granularity available) [$/ kW·h];

$\rho_t$ System capacity avoided cost forecast at time $t$, at interchange node (i.e. avoided generation capacity cost, AGCC, at substation node, ISO zone, or granularity available) [$/kW];

$\varsigma_t$ System emission avoided cost forecast at time $t$, at interchange node (i.e. average hourly price, at substation node, ISO zone, or granularity available) [$/kW·h];

$\sigma_t$ System ancillary services avoided cost forecast at time $t$, at interchange node (i.e. average hourly price, at substation node, ISO zone, or granularity available) [$/kW·h]

$\vartheta_t$ System renewable portfolio standard avoided cost forecast at time $t$, at interchange nodes (i.e. average hourly price, at substation node, ISO zone, or granularity available) [$/kW·h];

### *5.3.9 Solar Parameters*

$\tilde{P}_{w,t}^{W}$ Renewable power forecast of solar PV device $w$ in period $t$, [kW]

$C_{w,t}(\cdot)$ Operational cost to curtail solar PV device $w$ at time $t$, [\$/kW]

### 5.3.10 Line Parameters

$\bar{F}_{ij}$ Active power flow limit for line $ij$, [kW]

### 5.3.11 Decision Variables

The following continuous decision variables are to be determined:

$P_t^X$ Power exchange with grid at exchange in period $t$

$P_{w,t}^W$ Power produced by DER solar $w$ in period $t$

$P_{d,t}^{D-}$ Power reduction by DER flexible demand $d$ in period $t$

$P_{d,t}^{D+}$ Power increase by DER flexible demand $d$ in period $t$

$P_{s,t}^{S+}$ Power charge by storage s in period $t$

$P_{s,t}^{S-}$ Power discharge by storage s in period $t$

$E_{s,t}$ Energy stored in storage s in period $t$

$P_{g,t}^G$ Power produced by generator $g$ in period $t$

$R_{g,t}^{SR}$ Spinning reserve by generator $g$ in period $t$

$R_{g,t}^{NSR}$ Non-spinning reserve by generator $g$ in period $t$

$R_{g,t}^{OR}$ Operating reserve by generator $g$ in period $t$

$R_{s,t}^{SR}$ Spinning reserve by storage $s$ in period $t$

$R_{s,t}^{NSR}$ Non-spinning reserve by storage $s$ in period $t$

$R_{s,t}^{OR}$ Operating reserve by storage $s$ in period $t$

The following binary variables decision variables are to be determined:

$Z_{g,t}$ Commitment status for generator $g$ in period $t$

$V_{g,t}$ Startup status for generator $g$ in period $t$

$V_{g,t}^{HS}$ Hot startup status for generator $g$ in period $t$

$W_{g,t}$ Shutdown status for generator $g$ in period $t$

### *5.3.12 Objective Function*

Consider a DER portfolio $P$ with the following DERs: $D$ load devices, $Dr$ flexible temperature-related demand response loads, $K$ electric vehicles, $S$ energy storage devices and $W$ stochastic PV generators. The operational agent: DSO or aggregator seeks to optimally operate these DERs over a time horizon $\{1, \dots, t, \dots, T\}$ (i.e. the day-ahead market with a 24-hour horizon at 1-hour granularity). The portfolio is exposed to day-ahead prices $\pi_t$ for system avoided energy costs, $\rho_t$ for system capacity avoided costs,$\varsigma_t$ for system emissions avoided costs, $\sigma_t$ for system ancillary services avoided costs, $\vartheta_t$ for system renewable portfolio standard avoided costs. For DER portfolio $P$ at time $t$, let

$P_t^X, P_{g,t}^G, P_{w,t}^W, P_{d,t}^{D-}, P_{d,t}^{D+}, P_{s,t}^{s-}, P_{s,t}^{s+}$ be continuous variables representing power output for generators, solar curtailment, demand response, and energy storage, all in kW. The objective is to minimize the total costs consisting of: energy costs, system avoided costs, operational costs, and reserve costs.

$$\begin{aligned}\min C_P = \sum_{t\in\tau} \Big( & \lambda_t P_t^X - \lambda_t^{SR} SR_t^X - \lambda_t^{NSR} NSR_t^X - \lambda_t^{OR} OR_t^X - \pi_t\big(\tilde{P}_{d,t}^D - \\ & P_t^X\big) - \rho_t\big(\tilde{P}_{d,t}^D - P_t^X\big) - \varsigma_t\big(\tilde{P}_{d,t}^D - P_t^X + \textstyle\sum_g C_{g,t}\big(P_{g,t}^G\big)\big) - \sigma_t\big(\tilde{P}_{d,t}^D - P_t^X\big) - \\ & \vartheta_t\big(\tilde{P}_{d,t}^D - P_t^X + \textstyle\sum_g C_{g,t}\big(P_{g,t}^G\big)\big) + \textstyle\sum_w C_{w,t}\big(\tilde{P}_{w,t}^W - P_{w,t}^W\big) + \textstyle\sum_d C_{d,t}^{D-}\big(P_{d,t}^{D-}\big) + \\ & \textstyle\sum_d C_{d,t}^{D+}\big(P_{d,t}^{D+}\big) + \textstyle\sum_s C_{s,t}^{S-}\big(P_{s,t}^{s-}\big) + \textstyle\sum_s C_{s,t}^{S+}\big(P_{s,t}^{s+}\big) + \textstyle\sum_g \Big(C_g^{CS} V_{g,t} + \\ & \big(C_g^{HS} - C_g^{CS}\big)V_{g,t}^{HS} + C_g^{SD}\big(W_{g,t}\big) + C_g^{LV} P_{g,t}^G + \Big(C_g^{NL} + C_g^{LV} \underline{P_g}\Big) Z_{g,t}\Big) + \\ & + \textstyle\sum_g C_{g,t}^R\big(R_{g,t}^{SR} + R_{g,t}^{NSR} + R_{g,t}^{OR}\big) + \textstyle\sum_s C_{s,t}^R\big(R_{s,t}^{SR} + R_{s,t}^{NSR} + R_{s,t}^{OR}\big)\Big)\end{aligned} \tag{48}$$

where $P_t^X$ represents the total power exchanged between the DER portfolio and the electric grid, $\tilde{P}_{d,t}^D$ and $C_P$ represents the total cost during the time horizon $\{1, \ldots, t, \ldots, T\}$

Figure 27 shows a schematic view of a DER portfolio of solar panels, energy storage devices, flexible loads and electric vehicles that is interconnected to a distribution system D, which is connected to a bus in transmission system B. The portfolio can offer distribution-level services such as distribution capacity deferral, voltage support, reliability services, distribution-system demand response, etc. It can also offer DER transmission services such as energy, reserves, emissions reductions, deferral of system upgrades, and other ancillary services.

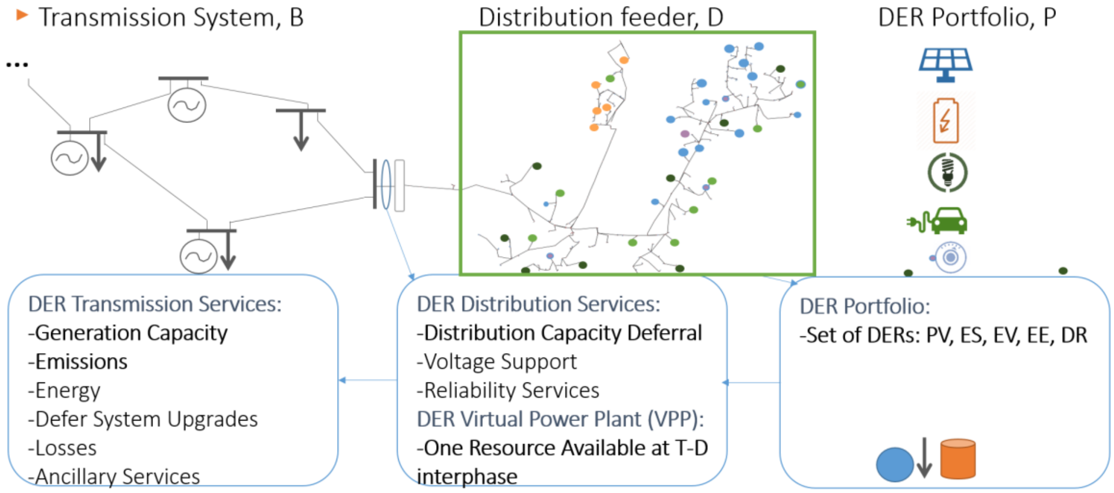


**Figure 27 – DER Portfolio Offering Distribution and Transmission Services**

*5.3.13 Power Balance Constraints*

The power balance at each time $t$ can be expressed as:

$$P_t^X = \sum_{g\in G}(\underline{P_g}Z_{g,t} + P_{g,t}^G) + \sum_{q\in Q}\tilde{P}_{w,t}^W - \sum_{k\in K}\tilde{P}_{k,t}^{EV} - \sum_{s\in S}P_{s,t}^{s+} + \sum_{s\in S}P_{s,t}^{s-} - \sum_{d\in D}P_{d,t}^D + \sum_{l\in L}P_{l,t}^L, \forall t \quad (49)$$

Where $\sum_{g\in G}P_{g,t}^G$ represents the aggregated power produced by generators at time $t$, $\sum_q \tilde{P}_{w,t}^W$ represents the aggregated power produced by the PV generators at time $t$, $\sum_{k\in K}\tilde{P}_{k,t}^{EV}$ represents the aggregated power consumed by the EVs at time $t$, $\sum_{\in S}P_{ESd,k,t} - \sum_{k\in S}P_{ESc,k,t}$ is the aggregated power discharge minus charge by energy storage devices at time $t$, and $\sum_{d\in D}P_{d,t}^D$ is the aggregated load at time $t$.

*5.3.14 Total DER Portfolio Reserve Constraint*

The total reserves constraints at each time $t$ can be expressed as:

$$\tilde{R}_t^{SR} = \sum_{g\in G}(R_{g,t}^{SR}) + \sum_{s\in S}(R_{s,t}^{-SR}) \quad \forall\, t \tag{50}$$

$$\tilde{R}_t^{NSR} = \sum_{g\in G}(R_{g,t}^{NSR}) + \sum_{s\in S}(R_{s,t}^{-NSR}) \quad \forall\, t \tag{51}$$

$$\tilde{R}_t^{OR} = \sum_{g\in G}(R_{g,t}^{OR}) + \sum_{s\in S}(R_{s,t}^{-OR}) \quad \forall\, t \tag{52}$$

*5.3.15 Energy Storage Constraints*

$$\underline{E_s} \leq E_{s,t} \leq \overline{E_s} \quad \forall t, s \tag{53}$$

$$0 \leq P_{s,t}^{S-} \leq \overline{P_s^{S-}} \quad \forall t, s \tag{54}$$

$$0 \leq P_{s,t}^{S+} \leq \overline{P_s^{S+}} \quad \forall t, s \tag{55}$$

$$E_{s,t} = E_{s,t-1} + \eta_s^{+} P_{s,t}^{S+} - \eta_s^{-} P_{s,t}^{S-} \quad \forall t \in [2, T], s \tag{56}$$

$$E_{s,T} \geq E_{s,t0} \quad \forall s \tag{57}$$

$$\left(P_{s,t}^{S-} + R_{s,t}^{SR} + R_{s,t}^{NSR} + R_{s,t}^{OR}\right)\eta_s^{-} \leq \overline{E_s} - E_{s,t} \quad \forall s \tag{58}$$

$$R_{s,t}^{SR} \leq \frac{\overline{P_{s,t}^{S-}}}{6} \quad \forall t, s \tag{59}$$

$$R_{s,t}^{SR} \leq \overline{P_s^{S-}} - P_{s,t}^{S-} \quad \forall t, s \tag{60}$$

$$R_{s,t}^{NSR} \le \frac{\overline{P_{s,t}^{S-}}}{6} \quad \forall t, s \tag{61}$$

$$R_{s,t}^{NSR} \le \overline{P_s^{S-}} - P_{s,t}^{S-} - R_{s,t}^{SR} \quad \forall t, s \tag{62}$$

$$R_{g,t}^{OR} \le \frac{\overline{P_{s,t}^{S-}}}{2} \quad \forall t, s \tag{63}$$

$$R_{g,t}^{OR} \le \overline{P_s^{S-}} - P_{s,t}^{S-} - R_{s,t}^{SR} - R_{s,t}^{NSR} \quad \forall t, s \tag{64}$$

Where: $\overline{P_s^{S-}}, \overline{P_s^{S+}}$ represent the minimum and maximum discharge and charge rates; $\overline{E_s}$ and $\underline{E_s}$ represent the maximum and minimum energy storage capacities. Finally, the last equation represents an energy conservation constraint with $\eta_{D,s}$, $\eta_{c,s}$ as discharge and charge efficiencies.

### *5.3.16 Generation Constraints*

The generator model is largely based on [35] and [82] and is presented here with no consideration of quadratic costs.

#### 5.3.16.1 Startup, Hot Startup and Shutdown Variables

The following equations characterize the constraints associated with startup, hot startup, and shutdown variables:

$$V_{g,t}^{HS} \le \sum_{\tau=t-T_g^{CS}-TD_g}^{t-1} W_{g,t}\,, \ \forall t \in \left[T_g^{CS} + TD_g + 1, T\right], g \tag{65}$$

$$V_{g,t}^{HS} \leq V_{g,t}, \quad \forall t, g \tag{66}$$

$$Z_{g,t} - Z_{g,t-1} = V_{g,t} - W_{g,t} \; \forall t, g \tag{67}$$

5.3.16.2 Power Output Limits

The following equations denote the constraints associated with power output limits:

$$P_{g,t}^{G} \leq \left(\overline{P_g} - \underline{P_g}\right) Z_{g,t} - \left(\overline{P_g} - SU_g\right) V_{g,t}, \forall t, g\text{:} TU_g = 1 \tag{68}$$

$$P_{g,t}^{G} \leq \left(\overline{P_g} - \underline{P_g}\right) Z_{g,t} - \left(\overline{P_g} - SD_g\right) W_{g,t+1}, \forall t, g\text{:} TU_g = 1 \tag{69}$$

$$P_{g,t}^{G} \leq \left(\overline{P_g} - \underline{P_g}\right) Z_{g,t} - \left(\overline{P_g} - SU_g\right) V_{g,t} - \left(\overline{P_g} - SD_g\right) W_{g,t+1}, \forall t, g\text{:} TU_g \geq 2 \tag{70}$$

5.3.16.3 Ramp Limits, Minimum Uptime and Downtime

The following equations denote the constraints associated with minimum uptime, minimum downtime and ramp limits:

$$\sum_{\tau=t-TU_g+1}^{t} V_{g,t} \leq Z_{g,t} \; \forall t \in \left[TU_g, T\right], g \tag{71}$$

$$\sum_{\tau=t-TD_g+1}^{t} W_{g,t} \leq 1 - Z_{g,t} \;\; \forall t \in \left[TD_g, T\right], g \tag{72}$$

$$-\overline{P_g^d} \leq P_{g,t}^G - P_{g,t-1}^G \leq \overline{P_g^u} \ \ \forall t, g \tag{73}$$

5.3.16.4 Spinning, Non-Spinning Reserve and Operating Reserve Constraints

The following equations denote the constraints associated with spinning reserve, non-spinning reserve, and operating reserve constraints:

$$R_{g,t}^{SR} \leq \frac{\overline{P_g^u}}{6} Z_{g,t} \ \ \forall t, g \tag{74}$$

$$R_{g,t}^{SR} \leq \overline{P_g} - ( P_{g,t}^G + \underline{P_g}) \ \ \forall t, g \tag{75}$$

$$R_{g,t}^{NSR} \leq \frac{SU_g}{6} \left(1 - Z_{g,t}\right) + \frac{\overline{P_g^u}}{6} Z_{g,t} \ \ \forall t, g \tag{76}$$

$$R_{g,t}^{NSR} \leq \overline{P_g} - \left(P_{g,t}^G + \underline{P_g}\right) - R_{g,t}^{SR} \ \ \forall t, g \tag{77}$$

$$R_{g,t}^{OR} \leq \frac{SU_g}{2} \left(1 - Z_{g,t}\right) + \frac{\overline{P_g^u}}{2} Z_{g,t} \ \ \forall t, g \tag{78}$$

$$R_{g,t}^{OR} \leq \overline{P_g} - \left(P_{g,t}^G + \underline{P_g}\right) - R_{g,t}^{SR} - R_{g,t}^{NSR} \ \ \forall t, g \tag{79}$$

$$P_{g,t}^G, R_{g,t}^{SR}, R_{g,t}^{NSR}, R_{g,t}^{OR} \geq 0, Z_{g,t}, V_{g,t}, V_{g,t}^{HS}, W_{g,t} \in \{0,1\}, \ \forall t, g \tag{80}$$

$$\sum_{g \in G} R_{g,t}^{SR} \geq \tilde{R}_t^{SR}, \ \sum_{g \in G} R_{g,t}^{NSR} \geq \tilde{R}_t^{NSR}, \ \sum_{g \in G} R_{g,t}^{OR} \geq \tilde{R}_t^{OR} \ \forall t \tag{81}$$

*5.3.17 Line Constraints*

The following constraints represent the line power flow limits:

$$-\bar{F}_{ij} \geq \gamma_{ij,k} \sum_{k \in N} P_{l,t} \leq \bar{F}_{ij} \ \forall ij \in N, t \tag{82}$$

Flexible Temperature-Related Load Constraints

*5.3.18 Flexible Temperature-Related Load Constraints*

$$P_{d,t}^{D} = \tilde{P}_{d,t}^{D} - P_{d,t}^{D-} + P_{d,t}^{D+}, \forall\, t, d \in Dr \tag{83}$$

$$P_{d,t}^{D} = \tilde{P}_{d,t}^{D}, \forall\, t, d \notin Dr \tag{84}$$

$$P_{d,t}^{D+} \leq \overline{P_{dr}^{D+}} \ \forall\, t, d \in Dr \tag{85}$$

$$P_{d,t}^{D-} \leq \overline{P_{dr}^{D-}} \ \forall\, t, d \in Dr \tag{86}$$

$$\gamma \cdot Conf_{min}(t) \leq \tilde{P}_{d,t}^{D} - P_{d,t}^{D-} + P_{d,t}^{D+} \leq \gamma \cdot Conf_{max}(t) \forall\, t, d \in Dr \tag{87}$$

$$\sum_{t \in T} P_{d,t}^{D} = \sum_{t \in T} \tilde{P}_{d,t}^{D} \ \ \forall\, t, d \in Dr \tag{88}$$

$\overline{P_{dr}^{D+}}$ and $\overline{P_{dr}^{D-}}$represent the maximum ramp up and down rate, respectively; $Conf_{min}(t)$ and $Conf_{max}(t)$ represent the minimum and maximum comfort constraints at time $t$ expressed as a deviation from historical demand power, $\tilde{P}_{d,t}^{D}(t)$; $\gamma \in [0,1]$ is a comfort factor defined through customer participation which represents the customer's flexibility to participate in the demand response program ($\gamma = 0$ if customer is not willing to participate). Finally, (88) represents energy conservation constraint.

## 5.4 Simulation Results

### *5.4.1 Test Case Details*

To demonstrate the DER economic schedule optimization, real data collected from Georgia Tech campus was used. As described in [83], the Georgia Tech campus is a smart grid testbed that includes more than 200 buildings with more than 400 smart meters. The testbed contains solar PV systems in multiple buildings. The testbed consists of various load types such as industrial, commercial and residential loads. Twelve different parking lots across the campus contain level-II electrical vehicle charging stations. As of 2015, there were more than 150 EVs registered on campus owned by students, faculty, and staff. Most of the buildings in the Georgia Tech campus have centralized heating and cooling services provided by several chiller plants. This gives Georgia Tech Facilities Department direct control of the HVAC loads within the campus. The data has been slightly modified to protect Georgia Tech's data privacy.

### *5.4.2 Use Case I: Virtual Power Plan or Microgrid Exposed to Real-Time Prices*

In this case only PV, flexible load, EVs and no generators are included. It is assumed that the campus participates on the real-time pricing, day-ahead schedule (RTP-DA-5) provided by Georgia Power. The total electricity bill can be partitioned into two parts: a standard bill and a real-time-price bill as shown in (89). Under the RTP-DA-5 tariff, a customer baseline load curve (CBL) is determined based on energy consumption history.

The standard bill ($C_{standard}$) is charged using a negotiated flat rate for the baseline load. The real-time-price bill ($C_{RTP}$) is charged by the deviation of energy consumption ($\tilde{P}^{D}_{d,t} - P^{X}_{t}$) from the baseline load curve times the day-ahead real-time price on the market $\lambda^{RTP}_{t}$ as shown in (90). During this program, Georgia Power provides the hourly projection of the energy price during the day ahead.

$$C_{total} = C_{standard} + C_{RTP} \tag{89}$$

$$C_{RTP\,P} = \sum_{t=1}^{T} \lambda^{RTP}_{t} \left(\tilde{P}^{D}_{d,t} - P^{X}_{t}\right) \tag{90}$$

The optimization model involves minimizing a linear objective function subject to linear constraints. MATLAB is used to solve this model while taking into consideration market prices and device-level constraints. Figure 28 shows the energy mix for the day of peak consumption before optimization. It is possible to see that a significant portion of the energy consumption is allocated to HVAC temperature related loads during the peak hours.

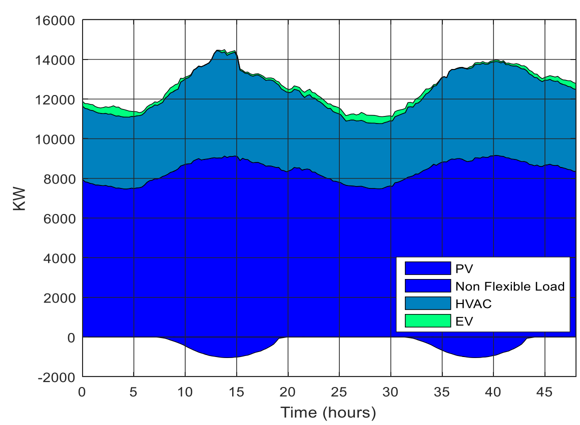


**Figure 28 – Use Case I: Energy Mix for the Two Days of Peak Consumption**

The operational cost depends on the price signal, $\pi^D(t)$ (in this case only the demand response program price signal is considered) which has daily and hourly fluctuation and is shown in Figure 29.

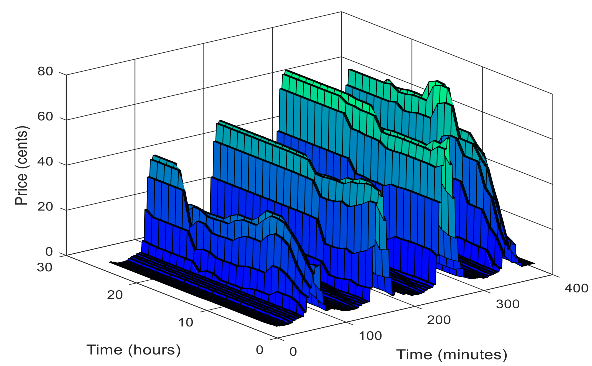


**Figure 29 – Use Case I: Price Signal for the Four Days of Peak Consumption**

Figure 30 shows that the optimization modeling is able to achieve peak reduction and load leveling for the temperature-related load while considering constraints associated with power balance, ramp rates, comfort and power limits. In addition, the coordination scheme enables a decreased consumption of the HVAC power during periods of high price, shifting operation to hours before price peak occurs in order to reduce the total cost.

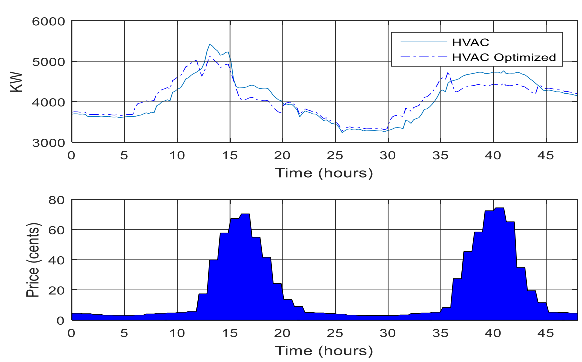


**Figure 30 – Use Case I: Optimized versus Baseline HVAC Schedule & Price Signal for the Two Days of Peak Consumption**

Figure 31 shows that the HVAC systems are kept within the comfort bounds. In this example, it is assumed that a higher comfort deviation is acceptable from 6am to 9pm, and a lower deviation is acceptable at night when temperatures are colder.

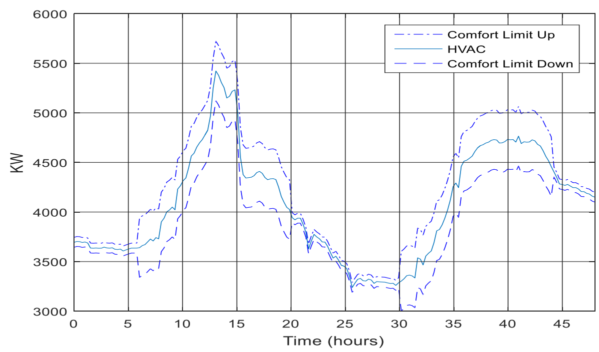


**Figure 31 – Use Case I: Customer-Defined Comfort Bounds (factor=1)**

Table 20 shows the total operational costs for the two days of peak consumption under different comfort scenarios. As the flexibility factor increases (i.e. approaches the maximum set comfort levels γ=1) the total operational cost decreases. This is consistent with the actual observed behavior: if the customer is willing to tolerate higher levels of HVAC deviation, higher savings will be perceived.

**Table 20 – Total Operational Costs for the Two Days of Peak Consumption**

| Case | Total Cost ($) |
|---|---|
| Baseline | 42,087 |
| Case 1 (γ=0.25) | 41,985 |
| Case 2 (γ=0.5) | 41,144 |
| Case 3 (γ=0.75) | 40,630 |
| Case 4 (γ=1) | 40,124 |

### *5.4.3 Use Case II: Distribution System Operator Exposed to Locational Marginal Prices*

The second use case is related to a distribution system operator (DSO) that is exposed to energy, spinning reserve, non-spinning reserve, and operating reserve prices from the transmission system. It also is exposed to avoided energy costs prices such as avoided energy costs, system energy capacity costs, system avoided emissions costs, and system avoided ancillary services costs. The system contains over six hundred nodes and lines and is populated with a generator, energy storage devices and solar PV devices as shown in Table 21.

**Table 21 – Distribution System Operator Case Number of Devices**

| | |
|---|---|
| Number of Buses | 611 |
| Number of Lines | 610 |
| Number of Generators | 1 |
| Number of Energy Storage Devices | 2 |
| Number of PV Devices | 7 |
| Number of Loads | 186 |

Figure 32 shows the total load and power provided by PV systems. The peak load has a value of 7242.77 [kW]. The maximum aggregated PV output is 1374 [kW].

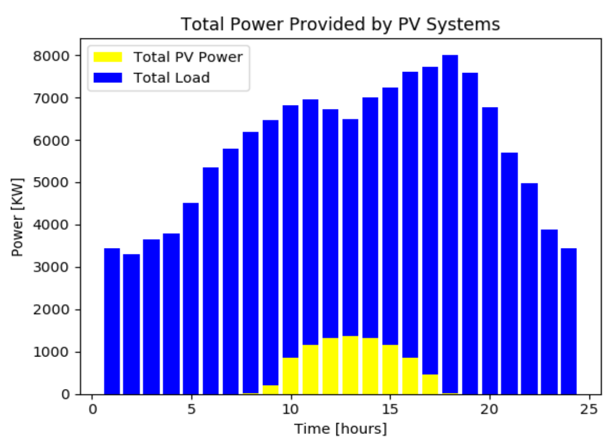


**Figure 32 – Use Case II: Total Load and Power Provide by PV Systems**

Figure 33 shows the output power and reserves for the distributed generator. We see that due to ramping constraints the generation output takes two hours to get to the maximum limit. It is assumed that when the expected load is bigger than 95 percent of the peak value, reserve services are procured from the generator (no energy storage reserve).

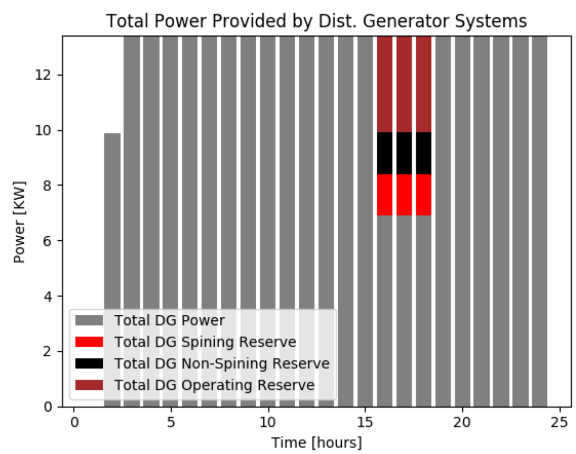


**Figure 33 – Use Case II: Distributed Generator Output Power and Reserves**

Figure 34 shows the scheduled charge and discharge power of the energy storage device. We can see that the storage device charges in the morning and discharges in the afternoon when the peak load takes place.

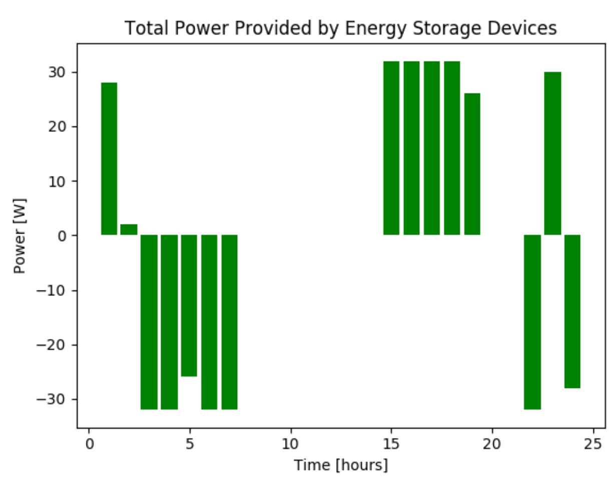


**Figure 34 – Use Case II: Energy Storage Charge and Discharge Schedule**

Table 22 shows the results of the optimization for different decision variables.

**Table 22 – Decision Variables Values Obtained from the DER Portfolio Optimization**

| | $P_{at}^{G}$ | $V_{at}$ | $V_{at}^{HS}$ | $W_{at}$ | $R_{at}^{SR}$ | $R_{at}^{NSR}$ | $R_{at}^{OR}$ | $E_{st}$ | $P_{st}^{S+}$ | $P_{st}^{S-}$ | $P_{wt}^{W}$ | $P_{dt}^{D}$ | $\tilde{P}_{dt}^{D}$ | $P_{t}^{X}$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 2.00 | 0.00 | 28.00 | 0.00 | 3477.47 | 3443.53 | 3449.47 |
| 2 | 9.89 | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 | 0.00 | 2.00 | 0.00 | 3322.32 | 3289.42 | 3310.43 |
| 3 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 32.00 | 32.00 | 0.00 | 0.00 | 3676.13 | 3639.74 | 3694.73 |
| 4 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 64.00 | 32.00 | 0.00 | 0.00 | 3820.78 | 3782.95 | 3839.37 |
| 5 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 90.00 | 26.00 | 0.00 | 0.00 | 4549.39 | 4504.34 | 4561.98 |
| 6 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 122.00 | 32.00 | 0.00 | 0.00 | 5395.80 | 5342.38 | 5414.39 |
| 7 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 154.00 | 32.00 | 0.00 | 0.00 | 5849.27 | 5791.36 | 5867.86 |
| 8 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 154.00 | 0.00 | 0.00 | 12.91 | 6249.08 | 6187.21 | 6222.76 |
| 9 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 154.00 | 0.00 | 0.00 | 205.20 | 6534.90 | 6472.21 | 6316.29 |
| 10 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 154.00 | 0.00 | 0.00 | 855.26 | 6871.23 | 6821.79 | 6002.57 |
| 11 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 154.00 | 0.00 | 0.00 | 1145.13 | 6953.85 | 6953.84 | 5795.32 |
| 12 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 154.00 | 0.00 | 0.00 | 1314.46 | 6718.57 | 6720.26 | 5390.71 |
| 13 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 154.00 | 0.00 | 0.00 | 1374.73 | 6420.61 | 6485.45 | 5032.48 |
| 14 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 154.00 | 0.00 | 0.00 | 1327.37 | 6927.54 | 6994.20 | 5586.77 |
| 15 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 122.00 | 0.00 | 32.00 | 1143.69 | 7170.34 | 7242.77 | 5981.24 |
| 16 | 8.91 | 0 | 0 | 0 | 1.5 | 1.5 | 3.5 | 90.00 | 0.00 | 32.00 | 862.43 | 7535.24 | 7611.35 | 6631.90 |
| 17 | 8.91 | 0 | 0 | 0 | 1.5 | 1.5 | 3.5 | 58.00 | 0.00 | 32.00 | 463.50 | 7643.86 | 7721.07 | 7139.45 |
| 18 | 8.91 | 0 | 0 | 0 | 1.5 | 1.5 | 3.5 | 26.00 | 0.00 | 32.00 | 4.30 | 7917.23 | 7997.21 | 7872.02 |
| 19 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 | 0.00 | 26.00 | 0.00 | 7519.17 | 7595.13 | 7479.77 |
| 20 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 | 0.00 | 0.00 | 0.00 | 6710.78 | 6778.53 | 6697.37 |
| 21 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 | 0.00 | 0.00 | 0.00 | 5703.16 | 5703.14 | 5689.75 |
| 22 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 32.00 | 32.00 | 0.00 | 0.00 | 5032.74 | 4986.93 | 5051.33 |
| 23 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 2.00 | 0.00 | 30.00 | 0.00 | 3915.70 | 3882.97 | 3872.29 |
| 24 | 13.4 | 0 | 0 | 0 | 0 | 0 | 0 | 30.00 | 28.00 | 0.00 | 0.00 | 3459.35 | 3426.75 | 3473.94 |

Figure 35 shows the total system avoided costs associated with energy, emissions, ancillary services, renewable portfolio standard and capacity costs calculated as the difference between the load and the optimized DER operation.

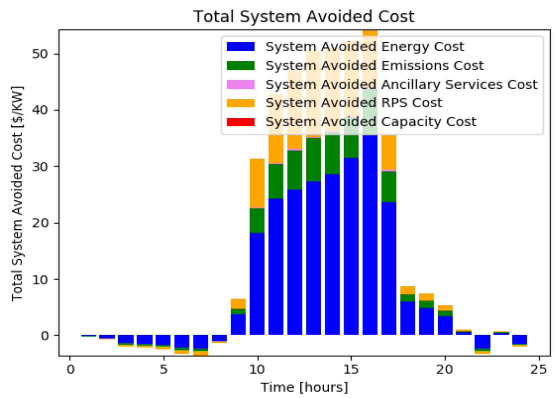


**Figure 35 – Use Case II: Total System Avoided Costs**

As is shown in Figure 36, the majority of the avoided costs in this case are attributed to the PV systems especially between periods 10 to 17 when solar output is at its highest. A significant portion of the avoided costs are related to emissions cost avoidance and renewable portfolio standard costs.

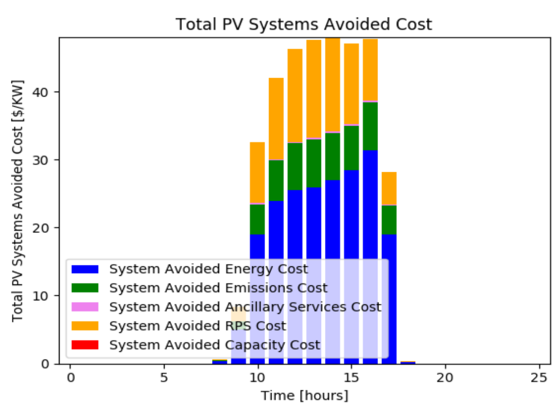


**Figure 36 – Use Case II: Total PV System Avoided Costs**

## 5.5 Summary

In this chapter, a DER economic optimization model has been presented. Section 5.2 explains that most models have concentrated on the optimization problem either at the home, microgrid, virtual power plant or aggregator-level usually looking at different groups of DERs. Nevertheless, there has not been significant attention given to the simultaneous net effect that a portfolio of devices such as energy storage, solar PV, distributed generation, and demand response could provide while taking into consideration market, system and device-level constraints. Also, no consideration of system avoided costs (such as avoided energy, avoided capacity, avoided ancillary services, avoided renewable portfolio standard), reserve services or detailed generation models including startup, shutdown cost, and minimum up and down times has been included in the objective function. In order to address these gaps, a mixed integer linear programming model is presented that describes different stages of modeling including: energy storage constraints, generator model constraints, flexible demand constraints, power balance constraints, reserve constraints and line constraints. The model is demonstrated in two use cases. The first use case is related to a campus acting as a virtual power plant that is exposed to a time varying price signal. In this case the major decision variables are associated with the flexible load. Results show that significant cost reductions are achieved using optimization while maintaining comfort defined bounds. The second use case is related to a distribution system operator that is interested in operating a portfolio of DERs at minimum cost. Results are presented from the standpoint of total system avoided costs obtained from the DER economic optimization. It is possible to see that by using DER optimization there is significant potential for DER avoided cost benefits.

# CHAPTER 6. STOCHASTIC OPTIMIZATION-BASED DER LOCATIONAL VALUATION

## 6.1 Introduction

This chapter presents a valuation method of DER portfolios that takes into consideration DER locational and temporal constraints, uncertainty of demand and prices and a risk of the expected costs. The proposed DER Portfolio Valuation Method intends to help in the quantification of the value of a DER portfolio located in a certain distribution system. This methodology aims to make available to electric distribution utilities a systematic approach to: 1) compare DER portfolios as alternatives to traditional grid infrastructure investments, and 2) enhance the distribution planning process in order to: a) integrate higher amounts of renewable energy, and b) facilitate the exchange of grid services by DERs as alternatives to traditional grid infrastructure investments. DER services can be used for: (1) optimization resulting in upgrade deferral of grid assets by DER management to shape feeder load, and (2) avoided costs through DER participation in wholesale energy markets.

This chapter is organized as follows section 6.2 presents an overview of the need for risk-averse stochastic optimization approaches for long-term planning and valuation. Section 6.3 presents the overall approach. Section 6.4 describes the risk-neutral two-stage stochastic mixed integer model. Section 6.5 describes the risk-averse two-stage stochastic model. The next section, 6.6, discusses scenario generation for modeling uncertainty. Then, Section 6.7 describes the simulation results, and Section 6.8 presents the chapter summary.

## 6.2 Uncertainty and Risk: The Need for Robust-Stochastic Optimization Applied to Long-Term Planning and Valuation

### *6.2.1 Optimization Methods for Resource Planning*

Decades ago, it was recognized in the electricity industry that in order to make the best investment decisions optimization techniques need to be applied to solve the complex long-term, mid-term and short-term planning problems. The industry evolved from using power-flow based solutions to optimization-based methods. Most of the work has focused on transmission systems and bulk generation. With the growing adoption of DERs at the distribution level, it is now necessary to have the same transition at the distribution system. Reference [84] provides an overview of optimization methods for electric utility resource planning. The analysis classifies the studies in: 1) resource and equipment planning that includes: long-term resource planning and production costing, long-range fuel planning, transmission and distribution planning and demand-side management implementation planning; 2) operations planning that includes: maintenance and production scheduling, fuel scheduling and unit commitment; and 3) real-time operations: dispatching, automatic protection. It describes a mixed-integer linear resource planning model and includes sections associated with transmission, multiple objectives, uncertainty and competition. Reference [85] presented an approach based on chronological simulation of integrated transmission and generation systems. It uses economic dispatch at each state by linearized optimal power flows and Monte Carlo sampling for generation capacities and load levels. The paper discusses the importance of production costing models to forecast the cost of operating generation systems, and the need to include uncertainty modeling that goes beyond the load duration curve due to the loss of chronological information. These models focus mostly on generation planning for transmission systems and do not include DER considerations or three-phase distribution network models.

### 6.2.2 Stochastic Optimization Methods for Resource Planning

The uncertainty of parameters such as future demand, prices and renewables makes the valuation and planning problem more challenging. In recent years, significant development in stochastic optimization methods and models has been developed to address this issue.

Reference [86] provides an overview of energy optimization models with uncertainty. It highlights the importance of stochastic optimization approach given that most investment decisions are permanent. Several models in power systems planning according to the planning horizon are presented including: 1) long-term planning models for long-term investment, 2) medium-term planning (1-3 years) such as reservoir management, and 3) short-term planning that includes one week, day ahead or hour ahead analysis such as unit commitment and economic dispatch.

Reference [87] provides an introduction to two-stage stochastic integer programming problems and discusses some of the challenges and research progress. The three challenges associated with solving a stochastic integer program are:1) evaluating the second-stage cost for: a particular realization of the uncertain parameters and a fixed first-stage decision; 2) evaluating the expected second-stage cost for a fixed first-stage decision; and 3) optimizing the expected second-stage cost. To address challenge 1, it is assumed that a second-stage problem's single evaluation is tractable. To address challenge 2, an approximation of the probability distribution of the uncertain parameters by a manageable distribution is proposed or the use of statistical estimates of the expected value function via Monte Carlo sampling. To address challenge 3, four types of developments are mentioned: 1) convex approximations of the value function, 2) stage wise decomposition algorithms, 3) scenario-wise decomposition, and 4) cut for deterministic equivalent MIP.

### *6.2.3 Risk Neutral and Risk Averse Optimization Methods for Resource Planning*

The second important consideration associated with valuation and investment decision making is associated with risk considerations.

Reference [88] proposes a two-stage stochastic optimization model for profit maximization of a price-taker power producer that needs to decide power generation capacity expansion. This work includes risk consideration by using the conditional value at risk approach. Reference [89] describes a long-term power generation capacity expansion planning problem for minimizing the investment cost and generation cost while taking into consideration the uncertainty represented by different future scenarios. This work uses a two-stage stochastic optimization and robust optimization method. Reference [90] proposes a stochastic optimization approach to solve the optimal capacity expansion planning of a microgrid in grid connected mode. This work takes into consideration multiple objectives including the minimization of net present cost, emissions, and non-renewable portion.

Given the nascent nature of DERs as an alternative to distribution capacity investments, at the distribution system level, long-term planning considering DERs is very limited. Most references have focused on the short-term optimization problems such as unit commitment. Reference [91] presents a mixed-integer linear programming (MILP) framework to solve a three-phase optimal power flow problem in the distribution networks. It uses a robust optimization where data uncertainties associated with load demand, wind speed and solar irradiance are modeled through bounds intervals as uncertainty sets. Reference [92] presents a three-phase optimal power flow for optimization of distributed generators. It uses a primal-dual interior point method. These models do not include long-term capacity expansion planning constraints such as budget and investment costs. Reference [93] presents a two-stage integer recourse model for optimizing electricity distribution. The following two problems are described: 1) contract with the power plants given specific quotas, and 2) the schedule of supply is for power plants and small generators. Reference [94] describes a multistage active distribution network planning model considering energy storage. The model co-optimizes investment decisions such as replacing or adding new lines and operation strategies such as the schedule of energy storage.

Most of the studies either have focused only transmission level long-term generation capacity expansion planning or on specific use cases such as microgrids. These studies do not include the simultaneous and combined consideration of DER portfolios that include: energy storage, demand response, solar PV, and distributed generators. In addition, most of the studies assume a single phase balanced system and no consideration of three phase unbalanced distribution systems network constraints. Finally, market prices for both distribution and transmission services such as system energy avoided costs, system capacity avoided costs, and emissions costs have not been included in the analysis. In summary, a new long-term planning valuation method that considers: integrated DER portfolios, uncertainty, risk, three-phase distribution networks, transmission and distribution market services is needed.

## 6.3 Approach

A stochastic optimization-based methodology is proposed to determine the net value of a DER portfolio at a distribution circuit taking into consideration locational, temporal constraints and operational dispatch schedules, and different scenarios of DER forecast and location. Using OMF, an electric utility distribution model can be imported in the following formats (CYMEDIST, WINDMILL and GRIDLAB-D). Then, the model can be populated with arbitrary combinations of DERs (PV, ES, DR, EVs). Based on the DERSP architecture and BCA framework different value categories (energy services) are identified. Based on the physical constraints, market constraints (prices), and DER operational constraints, the economic schedule of DER power production is taken into consideration together as well as investment costs and system avoided costs in the economic stochastic optimization module. The schedule result is provided as an input file to the GRIDLAB-D case and a quasi-steady-state time-series simulation is performed for 1 year at 1-hour granularity. The output results of changes in energy, capacity and other ancillary services are input to the financial valuation module. Financial projections are created and DER avoided costs are determined.

### *6.3.1 Facilities, Equipment and Information*

This research involves the use of three software packages: 1) Open Modeling Framework (OMF), 2) GridLAB-D, and 3) MATLAB. The software is installed in a laptop machine with processor Intel CORE i7 2.6GHz, 16GB of RAM. The research uses public information available in the OMF, NYREV and DRP proceedings from NY and CA.

## 6.4 The Risk-Neutral Two-Stage Stochastic Mixed Integer Model for Distribution Capacity Expansion Applied to DER Portfolio Valuation: Problem Formulation

A two-stage stochastic optimization model for minimizing the net present cost of a distributed energy resources portfolio owned by an electric distribution utility who has to decide between deploying a traditional capital investment solution for satisfying a distribution-system peak capacity or a non-wires alternative solution over a multi-year time horizon while taking into consideration operation constraints (power balance, network constraints), financial constraints (timing and value of deferred capital investment) and the uncertainty of the following parameters: wholesale market prices (energy, capacity, ancillary services, emissions), forecasts (solar radiation, load fluctuation) is presented. The parameter uncertainty is represented by scenarios on their values along the planning horizon and the associated probability of occurrence.

### *6.4.1 Sets and Indices*

DER candidate solutions:

$W_n$ set of candidate solar photovoltaic devices connected to node $n$;

$Q_n$ set of candidate energy efficient devices connected to node $n$;

$Dr_n$ set of candidate flexible load devices connected to node $n$;

$S_n$ set of candidate energy storage devices connected to node $n$;

$G_n$ set of candidate generator devices connected to node $n$;

Years, scenarios, demand, nodes, lines:

$\Omega$ set of scenarios, indexed by $\omega$;

$Y$ set of years in planning horizon, indexed by $y$;

$D$ set of demands, indexed by $d$;

$\tau$ set of time sub-periods in year $y$, indexed by $t \in \tau = \{1, \dots t_f\}$;

$N$ set of nodes, indexed by $n \in N = \{1, \dots n_f\}$;

$L$ set of lines connecting nodes $n, m$ , indexed by $l_{nm}$;

$P$ set of phases, indexed by $p \in P = \{a, b, c\}$;

### *6.4.2 Wholesale Market Prices*

$\lambda_{t,y,w}$ Energy price forecast at time $t$, in year $y$, in scenario $\omega$ at interchange node (i.e. locational based marginal price, LBMP, at substation node, ISO zone, or granularity available), [$/kW·h];

$\lambda_{t,y,w}^{SR}$ Spinning reserve price forecast at time $t$, in year $y$, in scenario $\omega$ at interchange node (i.e. locational based marginal price, LBMP, at substation node, ISO zone, or granularity available), [$/kW·h];

$\lambda_{t,y,\omega}^{NSR}$ Spinning reserve price forecast at time $t$, in year $y$, in scenario $\omega$ at interchange node (i.e. locational based marginal price, LBMP, at substation node, ISO zone, or granularity available), [$/kW·h];

$\lambda_{t,y,\omega}^{OR}$ Operating reserve price forecast at time $t$, in year $y$, in scenario $\omega$ at interchange node (i.e. locational based marginal price, LBMP, at substation node, ISO zone, or granularity available), [$/kW·h];

$\pi_{t,y,\omega}$ System energy avoided cost forecast at time at time $t$, in year $y$, in scenario $\omega$ at interchange node (i.e. locational based marginal price, LBMP, at substation node, ISO zone, or granularity available), [$/kW·h];

$\rho_{t,y,\omega}$ System capacity avoided cost forecast at time $t$, in year $y$, in scenario $\omega$ at interchange node (i.e. avoided generation capacity cost, AGCC, at substation node, ISO zone, or granularity available), [$/kW·h];

$\varsigma_{t,y,\omega}$ System emission avoided cost forecast at time $t$, in year $y$, in scenario $\omega$ at interchange node (i.e. average hourly price, at substation node, ISO zone, or granularity available), [$/kW·h];

$\sigma_{t,y,\omega}$ System ancillary services avoided cost forecast at at time $t$, in year $y$, in scenario $\omega$ at interchange node (i.e. average hourly price, at substation node, ISO zone, or granularity available), [$/kW·h];

$\vartheta_{t,y,\omega}$ System renewable portfolio standard avoided cost forecast at time $t$, in year $y$, in scenario $\omega$ at interchange nodes (i.e. average hourly price, at substation node, ISO zone, or granularity available), [$/kW·h];

### 6.4.3 *Energy Storage Parameters*

The following parameters are defined for each energy storage device:

$E_s^0$ Initial energy (beginning day ahead) in storage $s$, [kW·h]

$E_s^F$ Final energy (end day ahead) in storage $s$, [kW·h]

$\underline{E_s}$ Minimum energy in storage $s$, [kW·h]

$\overline{E_s}$ Maximum energy in storage $s$, [kW]

$\overline{P_s^{S+}}$ Maximum charge rate of storage $s$, [kW]

$\overline{P_s^{S-}}$ Maximum discharge rate of storage $s$, [kW]

$\eta_s^+$ Charge efficiency of storage $s$

$\eta_s^-$ Discharge efficiency of storage $s$

$C_{s,t}^{S-}(\cdot)$ Operational cost for discharging storage device $s$ at time $t$, [$/kW]

$C_{s,t}^{S+}(\cdot)$ Operational cost for charging storage device $s$ at time $t$, [$/kW]

$C_s^R$ Reserve cost of storage $s$, [$/kW]

### 6.4.4 *Generator Parameters*

The following parameters are defined for each generator device:

$\underline{P_g}$ Minimum generation of generator $g$, [kW]

$\overline{P_g}$ Maximum generation of generator $g$, [kW]

$\overline{P_g^u}$ Maximum ramp-up rate of generator $g$, [kW/h]

$\overline{P_g^d}$ Maximum ramp-down rate of generator $g$, [kW/h]

$SD_g$ Shutdown capability of generator $g$, [kW]

$SU_g$ Startup capability of generator $g$, [kW]

$T_g^{CS}$ Cold startup time of generator $g$, [h]

$TD_g$ Minimum downtime of generator $g$, [h]

$TU_g$ Maximum uptime of generator $g$, [h]

$C_g^{CS}$ Cold startup cost of generator $g$, [\$]

$C_g^{HS}$ Hot startup cost of generator $g$, [\$]

$C_g^{SD}$ Shutdown cost of generator $g$, [\$]

$C_g^{LV}$ Linear cost of generator $g$, [\$/kW]

$C_g^{NL}$ No-load cost of generator $g$, [\$]

$C_g^{R}$ Reserve cost of generator $g$, [\$]

### 6.4.5 Flexible Load Parameters

The following parameters are defined for each generator device:

$\underline{P_{dr}}$ Minimum power of flexible load device $dr$, [kW]

$\overline{P_{dr}}$ Maximum power of flexible load device $dr$, [kW]

$\overline{P_{dr}^{D+}}$ Maximum ramp-up rate of flexible load device $dr$, [kW/h]

$\overline{P_{dr}^{D-}}$ Maximum ramp-down rate of flexible load device $dr$, [kW/h]

$\eta_{dr}^{-}$ Constant associated with reducing flexible load $dr$

$\eta_{dr}^{+}$ Constant associated with increasing flexible load $dr$

$C_{dr,t}^{D-}(\cdot)$ Operational cost of flexible load decrease for device $dr$ at time $t$, [$/kW]

$C_{dr,t}^{D+}(\cdot)$ Operational cost of flexible load increase for device $dr$ at time $t$, [$/kW]

$\tau_{dr}^{F}$ Set of time sub-periods during which the flexible load is flexible

### 6.4.6 Demand Parameters

The following parameters are defined for each generator device:

$\tilde{P}_{d,t,y,\omega}^{D}$ Demand $d$ forecast in period $t$, in year $y$, in scenario $\omega$, [kW]

### 6.4.7 Solar Parameters

$\tilde{P}^{W}_{w,t,n,p,y,\omega}$ Renewable power forecast of solar PV device $w$, in period $t$, at node $n$, phase $p$, in year $y$, and scenario $\omega$, [kW]

$C_{w,t}(\cdot)$ Operational cost to curtail solar PV device $w$ at time $t$, [$/kW]

### *6.4.8 Line Parameters*

$T^{nm}_{l,t,p,q}$ Fraction of power transmitted from node $n$ to node $m$ in period $t$ that is lost due to electrical properties between phases $p$ and $q$

$\bar{P}^{nm}_{l,p}$ Maximum power rating of line $l$, phase $p$, [kW]

### *6.4.9 Reserve Parameters and Expected Load Not Served Parameters*

$\tilde{R}^{SR}_{t}$ System Reserve requirement for spinning reserve service, [kW]

$\tilde{R}^{NSR}_{t}$ System Reserve requirement for non-spinning reserve service, [kW]

$\tilde{R}^{OR}_{t}$ System Reserve requirement for operating reserve service, [kW]

$\bar{L}^{Shed}$ maximum load not served, [kW]

$C_{shed}$ Cost of not serving load, [$/kW]

### *6.4.10 Investment Costs Parameters*

$I_{x,w}$ Total investment cost to build a DER of type $x$, $x \in X = \{w, q, dr, s, g\}$; discounted to beginning of construction period, [$/kW]

$B$ Available budget, [$]

$H_x$ Construction time of a DER of candidate DER $x$, [years]

$K_x$ Industrial life of a DER of candidate technology $x$, [years]

$P_x^{nom}$ Installed capacity of generators of type g, [kW]

*6.4.11 First Stage Decision Variables*

The following variables are to be determined:

$U_{w,y,n}$ number of DER units of type: solar photovoltaic devices to be built in year y, at node $n$, (integer);

$U_{q,y,n}$ number of DER units of type: energy efficient devices to be built in year y, at node $n$, (integer);

$U_{dr,y,n}$ number of DER units of type: flexible load devices to be built in year y, at node $n$, (integer);

$U_{s,y,n}$ number of DER units of type: energy storage to be built in year y, at node $n$, (integer);

$U_{g,y,n}$ number of DER units of type: generator to be built in year y, at node $n$, (integer);

*6.4.12 Second Stage Decision Variables*

$P_{y,t,\omega}^0$ Power exchange with grid at exchange node (i.e. substation) in period $t$ in year $y$, in scenario $\omega$

$P^0_{y,t,p,\omega}$ Power at exchange node (i.e. substation) in year $y$ in period $t$ and phase $p$, in scenario $\omega$

$P^0_{n,y,t,p,\omega}$ Power in period $t$ in year $y$ at node $n$ and phase $p$, in scenario $\omega$

$P^{nm}_{l,y,t,p,\omega}$ Power flow in line $l$ from node $n$ to node $m$ in period $t$ in year $y$ and phase $p$, in scenario $\omega$

$P^{mn}_{l,y,t,p,\omega}$ Power flow in line $l$ from node $m$ to node $n$ in period $t$ in year $y$ and phase $p$, in scenario $\omega$

$P^W_{w,y,t,n,p,\omega}$ Power produced by DER solar $w$ in period $t$ in year $y$ at node $n$ and phase $p$, in scenario $\omega$

$P^Q_{q,y,t,n,p,\omega}$ Power contribution by DER energy efficiency $q$ in period $t$ in year $y$, at node $n$ and phase $p$, in scenario $\omega$

$P^{D-}_{d,y,t,n,p,\omega}$ Power reduction by DER flexible demand $d$ in period $t$ in year $y$, at node $n$ and phase $p$, in scenario $\omega$

$P^{D+}_{d,y,t,n,p,\omega}$ Power increase by DER flexible demand $d$ in period $t$ in year $y$, at node $n$ and phase $p$, in scenario $\omega$

$P^{S+}_{s,y,t,n,p,\omega}$ Power charge by storage s in period $t$ in year $y$, at node $n$ and phase $p$, in scenario $\omega$

$P^{S-}_{s,y,t,n,p,\omega}$ Power discharge by storage s in period $t$ in year $y$, at node $n$ and phase $p$, in scenario $\omega$

$P^{G}_{g,y,t,n,p,\omega}$ Power produced by generator $g$ in period $t$ in year $y$, at node $n$ and phase $p$, in scenario $\omega$

$E_{s,y,t,n,p,\omega}$ Energy stored in storage s in period $t$ in year $y$, at node $n$ and phase $p$, in scenario $\omega$

$P^{G}_{g,y,t,n,p,\omega}$ Power produced by generator $g$ in period $t$ in year $y$, at node $n$ and phase $p$, in scenario $\omega$

$R^{SR}_{g,y,t,n,\omega}$ Spinning reserve by generator $g$ in period $t$ in year $y$, at node $n$ and phase $p$, in scenario $\omega$

$R^{NSR}_{g,y,t,n,\omega}$ Non-spinning reserve by generator $g$ in period $t$ in year $y$, at node $n$ and phase $p$, in scenario $\omega$

$R^{OR}_{g,y,t,n,\omega}$ Operating reserve by generator $g$ in period $t$ in year $y$, at node $n$ and phase $p$, in scenario $\omega$

$R^{SR}_{s,y,t,n,\omega}$ Spinning reserve by storage $s$ in period $t$ in year $y$, at node $n$ and phase $p$, in scenario $\omega$

$R^{NSR}_{s,y,t,n,\omega}$ Non-spinning reserve by storage $s$ in period $t$ in year $y$, at node $n$ and phase $p$, in scenario $\omega$

$R^{OR}_{s,y,t,n,\omega}$ Operating reserve by storage $s$ in period $t$ in year $y$, at node $n$ and phase $p$, in scenario $\omega$

The following binary variables decision variables are to be determined:

$Z_{g,y,t,n,\omega}$ Commitment status for generator $g$ in period $t$ in year $y$, at node $n$ in scenario $\omega$

$V_{g,y,t,n,\omega}$ Startup status for generator $g$ in period $t$ in year $y$, at node $n$ in scenario $\omega$

$V^{HS}_{g,y,t,n,\omega}$ Hot startup status for generator $g$ in period $t$ in year $y$, at node $n$ in scenario $\omega$

$W_{g,y,t,n,\omega}$ Shutdown status for generator $g$ in period $t$ in year $y$, at node $n$ in scenario $\omega$

$L^{Shed}_{y,t,\omega}$ Expected load not served in period $t$ in year $y$, at node $n$ in scenario $\omega$

*6.4.13 Objective Function*

The objective function seeks a first-stage decision that minimizes first-stage costs and the expected cost of second-stage (recourse) decision. In this case, we minimize net present cost of the investment cost and the expectation of the sum of the system avoided costs, reserve costs and operational costs

$$
\begin{aligned}
&\min \textstyle\sum_y \frac{1}{(1+r)^y} \big(\sum_{g,p}\big(I_g P_g^{nom} U_{g,p,y}\big) + \sum_{dr,p}\big(I_{dr} P_{dr}^{nom} U_{dr,p,y}\big) + \\
&\textstyle\sum_{s,p}\big(I_s P_s^{nom} U_{s,p,y}\big) + \sum_{w,p}\big(I_w P_w^{nom} U_{w,p,y}\big) + \sum_\omega p_\omega \sum_{t\in T_y}\Big(\lambda_{t,y,\omega} P_{t,y,\omega}^0 - \\
&\textstyle\lambda_{t,y,\omega}^{SR} SR_t^X - \lambda_{t,y,\omega}^{NSR} NSR_t^X - \lambda_{t,y,\omega}^{OR} OR_t^X + \pi_{t,y,\omega}\big(\sum_{d,p} \tilde{P}_{d,t,n,p,y,\omega}^D - \\
&\textstyle P_{t,y,\omega}^0\big) + \rho_{t,y,\omega}\big(\sum_{d,p} \tilde{P}_{d,t,n,p,y,\omega}^D - P_{t,y,\omega}^0\big) + \varsigma_{t,y,\omega}\big(\sum_{d,p} \tilde{P}_{d,t,n,p,y,\omega}^D - \\
&\textstyle P_{t,y,\omega}^0 + \sum_{g\in G_n} P_{g,t,n,p,\omega}^G\big) + \sigma_{t,y,\omega}\big(\sum_{d,p} \tilde{P}_{d,t,n,p,y,\omega}^D - P_{t,y,\omega}^0\big) + \\
&\textstyle\vartheta_{t,\omega}\big(\sum_{d,p} \tilde{P}_{d,t,n,p,y,\omega}^D - P_{t,y,\omega}^0 + \sum_{g\in G_n} P_{g,t,n,p,\omega}^G\big) + \sum_{w,p} C_{w,t}\big(\tilde{P}_{w,t,n,p}^W - \\
&\textstyle P_{w,t,n,p,y,\omega}^W\big) + \sum_{d,p} C_{d,t}^{D-}\big(\tilde{P}_{d,t,n,p}^D - P_{d,t,n,p,y,\omega}^{D-}\big) + \sum_{d,p} C_{d,t}^{D+}\big(\tilde{P}_{d,t,n,p}^D + \\
&\textstyle P_{d,t,n,p,y,\omega}^{D+}\big) + \sum_{s,p} C_{s,t}^{S-}\big(P_{s,t,n,p,\omega}^{s-}\big) + \sum_{s,p} C_{s,t}^{S+}\big(P_{s,t,n,p,\omega}^{s+}\big) + \\
&\textstyle\sum_{g,p}\Big(C_g^{CS} V_{g,y,t,n,\omega} + \big(C_g^{HS} - C_g^{CS}\big) V_{g,y,t,n,\omega}^{HS} + C_g^{SD}\big(W_{g,y,t,n,\omega}\big) + \\
&\textstyle C_g^{LV} P_{g,y,t,n,p,\omega}^G + \Big(C_g^{NL} + C_g^{LV} \underline{P_g}\Big) Z_{g,y,t,n,\omega}\Big) + \sum_{g,p} C_{g,t}^R\big(R_{g,y,t,n,\omega}^{SR} + \\
&\textstyle R_{g,y,t,n,\omega}^{NSR} + R_{g,y,t,n,\omega}^{OR}\big) + \sum_s C_{s,t}^R\big(R_{s,y,t,n,\omega}^{SR} + R_{s,y,t,n,\omega}^{NSR} + R_{s,y,t,n,\omega}^{OR}\big) + \\
&C_{shed} L_{y,t,\omega}^{Shed}\Big)
\end{aligned}
\tag{91}
$$

*6.4.14 Distribution Node Network Balance*

$$
P_t^0 = \sum_p P_{t,p}^0 \ \forall t \in \tau \tag{92}
$$

$$
\begin{aligned}
P_{t,p}^0 + \sum_{g\in G_n} P_{g,t,n,p,\omega}^G + \sum_{w\in W_n} P_{w,t,n,p,\omega}^W + \sum_{s\in S_n} (P_{s,t,n,p,\omega}^{S-} - P_{s,t,n,p,\omega}^{S+}) \\
= \sum_{d\in D_n} P_{d,t,n,p,\omega}^D + \sum_{l\in L_n} P_{l,t,p,\omega}^{nm} \ \ \forall t \in \tau, \forall n \in N, \forall p \in P
\end{aligned}
\tag{93}
$$

*6.4.15 Node Network Balance*

$$\sum_{g\in G_n} P^{G}_{g,t,n,p,\omega} + \sum_{w\in W_n} P^{W}_{w,t,n,p,\omega} + \sum_{s\in S_n} (P^{S-}_{s,t,n,p,\omega} - P^{S+}_{s,t,n,p,\omega}) = \sum_{d\in D_n} P^{D}_{d,t,n,p,\omega} + \sum_{l\in L_n} P^{nm}_{l,t,p,\omega}\ \forall t \in \tau, \forall n \in N, \forall p \in P \tag{94}$$

*6.4.16 Line Power Balance*

$$P^{nm}_{l,t,p,\omega} = -\sum_{p} T^{nm}_{l,t,p,q} P^{mn}_{l,t,p,\omega}\ \forall l \in L, t \in \tau \tag{95}$$

*6.4.17 Line Capacities*

$$-\bar{P}^{nm}_{l,p} \leq \bar{P}^{nm}_{l,t,p,\omega} \leq \bar{P}^{nm}_{l,p}\ \forall p \in P, \forall l \in L, t \in \tau \tag{96}$$

*6.4.18 Total DER Portfolio Reserve Constraint*

The total reserves constraints at each time $t$ can be expressed as:

$$\tilde{R}^{SR}_{t} = \sum_{g\in G}(R^{SR}_{g,y,t,n,\omega}) + \sum_{s\in S}(R^{SR}_{s,y,t,n,\omega})\ \ \forall\, t \tag{97}$$

$$\tilde{R}^{NSR}_{t} = \sum_{g\in G}(R^{NSR}_{g,y,t,n,\omega}) + \sum_{s\in S}(R^{NSR}_{s,y,t,n,\omega})\ \forall\, t \tag{98}$$

$$\tilde{R}^{OR}_{t} = \sum_{g\in G}(R^{OR}_{g,y,t,n,\omega}) + \sum_{s\in S}(R^{OR}_{s,y,t,n,\omega}) + L^{Shed}_{y,t,\omega}\ \forall\, t \tag{99}$$

$$L^{Shed}_{y,t,\omega} \leq \bar{L}^{Shed}\ \ \forall\, t \tag{100}$$

*6.4.19 Generator Capacities*

The power produced $P^{G}_{g,t,n,p,\omega}$ by all new DERs of type distributed generator at node $n$ at phase $p$ in year $y$ in scenario $\omega$ is bounded by the number of DER units available times the maximum or minimum generation of generator $g$.

$$U_{g,y,n}\,\underline{P^{G}_{g}} \leq \sum_{p \in P} P^{G}_{g,t,n,p,\omega} \leq \overline{P^{G}_{g}} U_{g,y,n} \ \forall g \in G, \forall n \in N, t \in \tau \tag{101}$$

*6.4.20 Generator Ramp Up and Ramp Down*

$$0 \leq \sum_{p \in P} P^{G}_{g,t,n,p,\omega} - \sum_{p \in P} P^{G}_{g,t-1,n,p,\omega} \leq \overline{P^{Gu}_{g}} \ \forall g \in G, \forall n \in N, t \in \tau \tag{102}$$

$$0 \leq \sum_{p \in P} P^{G}_{g,t-1,n,p,\omega} - \sum_{p \in P} P^{G}_{g,t,n,p,\omega} \leq \overline{P^{Gd}_{g}} \ \forall g \in G, \forall n \in N, t \in \tau \tag{103}$$

*6.4.21 Storage Energy Conservation*

$$E_{s,t} = E_{s,t-1} + \eta^{+}_{s} \sum_{p \in P} P^{S+}_{s,t,n,p,\omega} - \eta^{-}_{s} \sum_{p \in P} P^{S-}_{s,t,n,p,\omega} \ \ \forall s \in S, \forall n \in N, t \in \tau \tag{104}$$

*6.4.22 Storage Final Charge*

$$E_{s,T} \geq E_{s,0} \forall s \in S \tag{105}$$

*6.4.23 Storage Charge and Discharge Rates*

$$0 \leq \sum_{p \in P} P^{S+}_{s,t,n,p,\omega} \leq \overline{P^{S+}_{s}} U_{s,y,n} \ \forall s \in S, t \in \tau \tag{106}$$

$$0 \leq \sum_{p \in P} P^{S-}_{s,t,n,p,\omega} \leq \overline{P^{S-}_{s}} U_{s,y,n} \; \forall s \in S, t \in \tau \tag{107}$$

*6.4.24 Storage Energy Limits*

$$U_{s,y,n} \underline{E_s} \leq E_{st} \leq \overline{E_s} \, U_{s,y,n} \; \forall s \in S, t \in \tau \tag{108}$$

*6.4.25 Solar Limited to their Potential Forecasted Values*

$$P^{W}_{w,t,n,p,\omega} \leq \tilde{P}^{W}_{w,t,n,p,\omega} U_{g,y,n} \tag{109}$$

*6.4.26 Flexible Load Response Energy Conservation*

$$E_{d,t} = E_{d,t-1} + \eta^{+}_{d} \sum_{p \in P} P^{D+}_{d,t,n,p,\omega} - \eta^{-}_{d} \sum_{p \in P} P^{D-}_{d,t,n,p,\omega} \tag{110}$$

*6.4.27 Flexible Load Capacity Limits*

$$0 \leq \sum_{p \in P} P^{D+}_{d,t,n,p,\omega} \leq \overline{P^{D+}_{d}} \, U_{dr,y,n} \forall d \in D_{dr}, t \in \tau \tag{111}$$

$$0 \leq \sum_{p \in P} P^{D-}_{d,t,n,p,\omega} \leq \overline{P^{D-}_{d}} U_{dr,y,n} \; \forall d \in D_{dr}, t \in \tau \tag{112}$$

*6.4.28 Minimum Total Energy*

$$\sum_{t \in \tau^{F}_{d}}^{T} \left( \tilde{P}^{D}_{d,t,n,p} + P^{D+}_{d,t,n,p,\omega} - P^{D-}_{d,t,n,p,\omega} \right) = 0 \;\; \forall d \in D_{dr}, t \in \tau \tag{113}$$

$$P^{D}_{d,t,n,p,\omega} = \tilde{P}^{D}_{d,t,n,p} + P^{D+}_{d,t,n,p,\omega} - P^{D-}_{d,t,n,p,\omega}\ \forall d \in D_{dr}, t \in \tau \tag{114}$$

$$P^{D}_{d,t,n,p,\omega} = \tilde{P}^{D}_{d,t,n,p} \forall d \notin D_{dr}\ t \in \tau \tag{115}$$

*6.4.29 Land Space, Maximum Rooftop Space Available, Administrative Permits or Other User-Defined Constraints*

Following [88], [89], considerations related with maximum number of units either due to land space or administrative permits needs to be considered. In the total number of years corresponding to the planning horizon, the total number of DERs constructed should be bounded above by the number $Z_x$ for every candidate DER $x$. $Z_x$ represents the maximum potential number of DER units of type $x$ that can be built and constrained by: maximum rooftop space available, land space, administrative permits or other site-specific constraints. The integer variable $u_{x,v,n}$ indicates the number of DERs of type $x \in X = \{w, q, dr, s, g\}$ whose construction has to be started in year $y$.

$$\sum_{y} u_{x,y,n} \leq Z_{x,n} \tag{116}$$

*6.4.30 Construction Time Constraints*

The new DER of type $x \in X = \{w, q, dr, s, g\}$ is available in year $y$ at node $n$ if its construction time $H_x$ is completed and industrial life $K_x$ is not ended.

$$U_{x,y,n} = \sum_{y-(H_x+K_x)+1 \leq v \leq y-K_x} u_{x,v,n} \tag{117}$$

### 6.4.31 Budget Constraints

The total investment in all new DERs of type $x \in X = \{w, q, dr, s, g\}$ needs to be less than the available budget $B$.

$$\sum_{y} \frac{1}{(1+r)^{y}} \sum_{x} \left( I_x P_x^{nom} U_{x,y} \right) \leq B \tag{118}$$

## 6.5 The Risk-Averse Two-Stage Stochastic Mixed Integer Model for Distribution Capacity Expansion Problem Formulation

### 6.5.1 Background Theory

Uncertainty is addressed by using the two-stage stochastic model to minimize the expected cost of energy operations under different scenarios or the uncertain load forecast, prices and renewables forecast. The second consideration is associated with risk. Risk is a measure of how volatile the expected costs are. Several approaches exist to measure risk that include variance, a worst-case scenario analysis, standard deviation, value-at-risk or conditional value-at risk [89]. Studies in the area of financial optimization [95] have described the properties of using a conditional value at risk approach. As it is stated in [96], Value at Risk (VaR) is a measure of the worst expected loss at a given confidence level, over a given horizon. In particular, in the area of two-stage stochastic programming mean-risk models such as conditional value-at risk have been proposed for risk averse approaches to renewable investment planning [97]. Conditional Value-at–Risk (CVaR) has the advantage of being a risk measure that despite the discontinuous and nonconvex properties of mixed-integer-linear programs value functions associated with random variables is structurally consistent and compliant to algorithmic treatment [98]. The conditional value at risk is used in this study. In order to present the risk averse model first the standard two-stage stochastic integer program is presented. Based on [87] the standard two-stage stochastic integer program optimization can be expressed as:

$$\min_{x} c^T x + \mathbb{E}_P[Q(x,\omega)] \tag{119}$$

$$s.t. Ax = b,$$

$$x \in \mathbb{R}_+^{n_1 - p_1} \times \mathbb{Z}_+^{p_1}$$

where

$$Q(x,\omega) := \min_{x} q^T y \tag{120}$$

$$s.t. Wy = h - Tx,$$

$$y \in \mathbb{R}_+^{n_2 - p_2} \times \mathbb{Z}_+^{p_2}$$

Where $x$ represents the first-stage decision and $y$ represents the second-stage decisions, $\omega$ represents the uncertain data with known distribution $P$ and the parameters $(q, h, T)$ are actual realization of the random data for the second-stage, the parameters $n_1, n_2, p_1, p_2$ are nonnegative integers with $p_1 \leq n_1$ and $p_2 \leq n_2$.

6.5.1.1 Scenario Decomposition

If the number of scenarios is small, then it is possible to use cuts for deterministic equivalent MIP approach by directly solving the deterministic equivalent MIP using a solver such as CPLEX [87]. Assuming that the random parameter takes one of a finite set of values called scenarios $\{\omega_1, \dots, \omega_S\}$ each of the scenarios have probabilities $\{p_1, \dots, p_S\}$ , the two-stage stochastic integer program can be formulated as:

$$\min_x c^T x + \sum_{s=1}^{S} p_s q_s^T y_s \tag{121}$$

$$s.t. Ax = b,$$

$$T_s x + W_s y_s = h_s \qquad s = 1, \dots, S,$$

$$x \in \mathbb{R}_+^{n_1 - p_1} \times \mathbb{Z}_+^{p_1} \qquad s = 1, \dots, S,$$

$$y_s \in \mathbb{R}_+^{n_2 - p_2} \times \mathbb{Z}_+^{p_2}$$

6.5.1.2 Risk-Averse Two-Stage Stochastic Integer Program

Based on [98], for $Q(x, \omega)$the $\alpha$ Conditional Value at Risk can be expressed as:

$$\phi_\alpha(x) = \min_{\eta \in \theta_s} f(\alpha, \eta, x), \tag{122}$$

Where

$$f(\alpha, \eta, x) := \eta + \frac{1}{1 - \alpha} \mathbb{E}[Q(x, \omega) - \eta]_+ \tag{123}$$

Then, two stage stochastic programming with mean risk aversion can be expressed as:

$$\min_x c^T x + \lambda[\eta + \frac{1}{1-\alpha}\sum\nolimits_{s=1}^{S} p_s\theta_s] \tag{124}$$

$$\theta_s \geq 0\,, \qquad s = 1, \dots, S,$$

$$\theta_s \geq q_s^T y_s - \eta\,, \qquad s = 1, \dots, S,$$

Where $\eta \in \mathbb{R}$ and and $\theta_s \in \mathbb{R}_+$.

### *6.5.2 Application to the Capacity Expansion Using a DER Portfolio Problem*

The risk averse two-stage SIP can be then applied to the case of distribution capacity expansion using a DER portfolio as follows:

$$\begin{aligned} \min \sum_y \frac{1}{(1+r)^y} (\sum_{g,p} \left(I_g P_g^{nom} U_{g,p,y}\right) + \sum_{r,p} \left(I_r P_r^{nom} U_{r,p,y}\right) \\ + \sum_{s,p} \left(I_s P_s^{nom} U_{s,p,y}\right) + \sum_{w,p} \left(I_w P_w^{nom} U_{w,p,y}\right) + \lambda[\eta \\ + \frac{1}{1-\alpha} \sum_\omega p_\omega\, \theta_\omega] \end{aligned} \tag{125}$$

where

$$\theta_\omega \geq 0\,, \forall\ \omega \tag{126}$$

$$\theta_\omega \geq M_\omega - \eta\,, \omega$$

Where $\eta \in \mathbb{R}$ and and $\theta_\omega \in \mathbb{R}_+$ and

$$M_{\omega} = \sum_{t \in T_y} \Big( \lambda_{t,y,\omega} P^0_{t,y,\omega} - \lambda^{SR}_{t,y,\omega} SR^X_t - \lambda^{NSR}_{t,y,\omega} NSR^X_t - \lambda^{OR}_{t,y,\omega} OR^X_t + \pi_{t,y,\omega} (\sum_{d,p} \tilde{P}^D_{d,t,n,p,y,\omega} - P^0_{t,y,\omega}) + \rho_{t,y,\omega} (\sum_{d,p} \tilde{P}^D_{d,t,n,p,y,\omega} - P^0_{t,y,\omega}) + \varsigma_{t,y,\omega} (\sum_{d,p} \tilde{P}^D_{d,t,n,p,y,\omega} - P^0_{t,y,\omega} + \sum_{g \in G_n} P^G_{g,t,n,p,\omega}) + \sigma_{t,y,\omega} (\sum_{d,p} \tilde{P}^D_{d,t,n,p,y,\omega} - P^0_{t,y,\omega}) + \vartheta_{t,\omega} (\sum_{d,p} \tilde{P}^D_{d,t,n,p,y,\omega} - P^0_{t,y,\omega} + \sum_{g \in G_n} P^G_{g,t,n,p,\omega}) + \sum_{w,p} C_{w,t} \big( \tilde{P}^W_{w,t,n,p} - P^W_{w,t,n,p,y,\omega} \big) + \sum_{d,p} C^{D-}_{d,t} \big( \tilde{P}^D_{d,t,n,p} - P^{D-}_{d,t,n,p,y,\omega} \big) + \sum_{d,p} C^{D+}_{d,t} \big( \tilde{P}^D_{d,t,n,p} + P^{D+}_{d,t,n,p,y,\omega} \big) + \sum_{s,p} C^{S-}_{s,t} \big( P^{s-}_{s,t,n,p,\omega} \big) + \sum_{s,p} C^{S+}_{s,t} \big( P^{s+}_{s,t,n,p,\omega} \big) + \sum_{g,p} \Big( C^{CS}_g V_{g,y,t,n,\omega} + \big( C^{HS}_g - C^{CS}_g \big) V^{HS}_{g,y,t,n,\omega} + C^{SD}_g \big( W_{g,y,t,n,\omega} \big) + C^{LV}_g P^G_{g,y,t,n,p,\omega} + \Big( C^{NL}_g + C^{LV}_g \underline{P_g} \Big) Z_{g,y,t,n,\omega} \Big) + \sum_{g,p} C^R_{g,t} \big( R^{SR}_{g,y,t,n,\omega} + R^{NSR}_{g,y,t,n,\omega} + R^{OR}_{g,y,t,n,\omega} \big) + \sum_s C^R_{s,t} \big( R^{SR}_{s,y,t,n,\omega} + R^{NSR}_{s,y,t,n,\omega} + R^{OR}_{s,y,t,n,\omega} \big) \Big) \tag{127}$$

## 6.6 Scenario Generation

### *6.6.1 Modeling Distribution System Uncertainty*

The model of future values of demand, renewable generation and prices is a necessary step in the process of valuation and long-term planning. Reference [99], provides a review of long-term and medium-term load forecasting techniques. The approaches to long-term load forecasting can be classified in: 1) time series approach, 2) econometric approach, and 3) end use approach. The time series approach assumes that there is a trend in the data such as a linear trend, polynomial trend and logarithmic trend. However, time series approach might not perform well when there is a lot of variability. Some methods to account for variability include: moving average, autoregressive-moving average models

[100]. The econometric approaches use socio-economic factors and estimate their relationship with demand [101]. Finally, the end use approach takes into consideration individual devices, amount of use and number of devices. Some methods for long-term load forecasting include: regression based [102], artificial intelligence using fuzzy logic [103], artificial neural networks [104], probabilistic methods [105], [106] . Several electric utilities are exploring also the use of software packages such as GridLAB-D [107], OpenDSS [108] for advanced distribution modeling and LoadSEER for econometric load forecasting [109]. However, most of these packages do not include optimization considerations related to valuation and long-term planning.

### *6.6.2 Using Prophet for Scenario Generation*

The model used for scenario generation uses the time series model proposed in [110] and its basis are presented here. Prophet is a method for forecasting time series data that is robust to missing data, shifts in the trend and significant outliers. The model uses a decomposable time series model with three model components: holidays, tendency, and seasonality. The method is proposed as an alternative to the automatic autoregressive moving average (ARIMA) [111] forecast model due to large trend errors when there is a change in trend near the limit period. It is expressed as:

$$y_t = g_t + s_t + h_t + \epsilon_t \tag{128}$$

where $g_t$ is the trend function that models non-periodic changes of the time series, $s_t$ represents periodic changes (weekly, yearly seasonality), $h_t$ are the impacts of holidays that happen on irregular days, and $\epsilon_t$ is the error term. In order to implement the trend model a nonlinear, saturating growth model based on a logistic growth model is used as follows:

$$g_t = \frac{C_t}{1 + \exp(-(k_t + a_t^T \delta)(t - (m + a_t^T \gamma))} \tag{129}$$

Where $C_t$ is a time-varying capacity, $k_t$ is a time varying growth rate and $m$ is an offset parameter, $\delta$ is a vector of rate adjustments and

$$a_{jt} = \begin{cases} 1, if\ t \geq s_j \\ 0, otherwise \end{cases} \tag{130}$$

Where $s_j \quad j \in 1, \dots, S$ are the time change points where growth rate changes. And

$$\gamma_j = (s_j - m - \sum_{l<j} \gamma_l)(1 - \frac{k + \sum_{l<j} \delta_l}{k + \sum_{l<j} \delta_l} \tag{131}$$

where $\gamma$ represents the change adjustment at changepoint $j$.

The seasonality is based on Fourier series that is expressed as:

$$s_t = \sum_{n=1}^{N} \left( a_n \cos\left(\frac{2\pi nt}{P}\right) + b_n \sin\left(\frac{2\pi nt}{P}\right) \right) \tag{132}$$

Where $P$ represents the seasonality period (yearly, weekly,etc.)

#### 6.6.2.1 Incorporating Uncertainty

Prophet by default considers uncertainty in the trend and observation noise. In case that uncertainty in seasonality is considered, it uses full Bayesian sampling by employing a Markov Chain Monte Carlo (MCMC) sampling method. Details about this method are beyond the scope of this research.

In reality, load forecasting requires several years of data associated with weather, GDP, temperature, historical DER adoption, policy goals, technical studies, etc. This is beyond the scope of this research. Ideally scenario generation will use the load forecast obtained from corporate forecasts, disaggregated at the substation level. Several efforts including the one being led by the CA working group on DER growth scenarios and distribution load forecasting [112] are working on considering system-wide DER adoption (PV adoption, transportation electrification, energy efficiency forecasts and demand response forecasts), load forecasting at the distribution level and methodologies for disaggregation of system-level DER forecast to circuits.

## 6.7 Simulation Results

### *6.7.1 Test Case Details*

The stochastic model and its risk averse version have been implemented in Gurobi. The test case used is the same distribution system described in chapter V. It contains over six hundred nodes and lines and it is populated with a generator, energy storage devices and solar PV devices. Table 23 contains a summary of the case.

**Table 23 – Distribution System Case Load Flow Summary**

| **Total Summary** | **kW** | **kvar** | **kVA** | **PF(%)** |
|---|---|---|---|---|
| Sources (Swing) | 7433.57 | 1676.17 | 7620.21 | 97.55 |
| Generators | 860.27 | 0 | 860.27 | 100 |
| **Total Generation** | **8293.84** | **1676.17** | **8461.52** | **98.02** |
| Load Read (Non-Adjusted) | 9662.22 | 7246.66 | 12077.78 | 80 |
| Load Used (Adjusted) | 8170.7 | 6128.02 | 10213.38 | 80 |
| Shunt Capacitors (Adjusted) | 0 | -4580.91 | 4580.91 | 0 |
| Shunt Reactors (Adjusted) | 0 | 0 | 0 | 0 |
| Motors | 0 | 0 | 0 | 0 |
| **Total Loads** | **8170.7** | **1547.12** | **8315.88** | **98.25** |
| Cable Capacitance | 0 | -88.72 | 88.72 | 0 |
| Line Capacitance | 0 | -1.5 | 1.5 | 0 |
| **Total Shunt Capacitance** | **0** | **-90.22** | **90.22** | **0** |
| Line Losses | 59.06 | 150.09 | 161.29 | 36.61 |
| Cable Losses | 64.08 | 69.18 | 94.3 | 67.96 |
| Transformer Load Losses | 0 | 0 | 0 | 0 |
| Transformer No-Load Losses | 0 | 0 | 0 | 0 |
| **Total Losses** | **123.14** | **219.27** | **251.48** | **48.97** |

### *6.7.2 Load Scenarios*

The total yearly load obtained from the sum of advanced metering data for a distribution system is shown in Figure 37

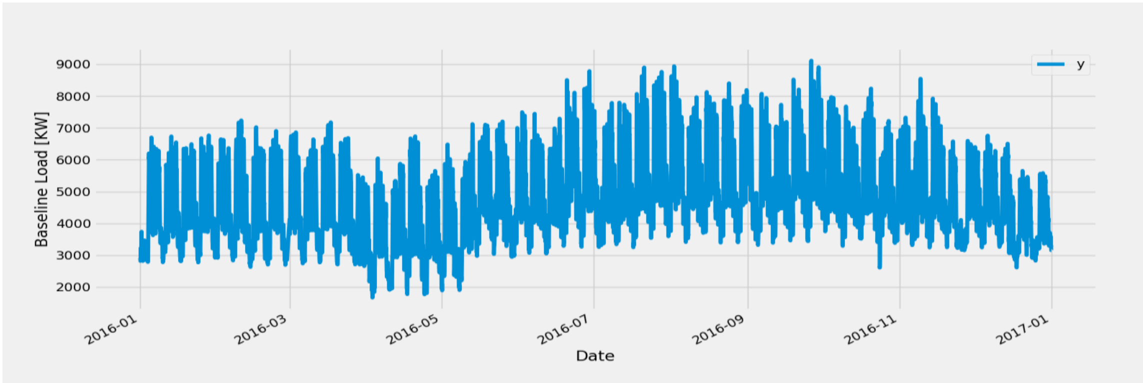


**Figure 37 – Baseline Time Series Load**

Using the time series method described in section 6.7.2, three scenarios are obtained for one year with an uncertainty interval of 80%, and saturation values.

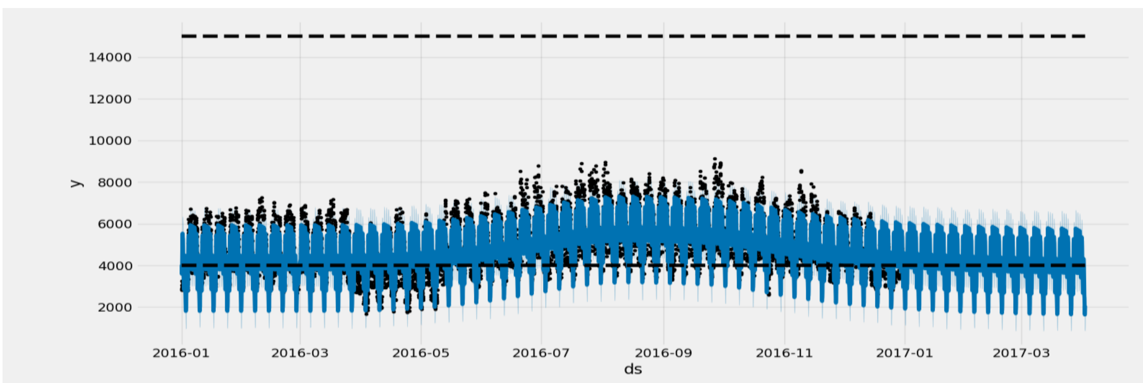


**Figure 38 – Load Scenarios for 1 Year Ahead**

Figure 39 shows the load scenarios using different lower and upper bounds on the time series data. It is possible to see that a downward trend is observed which is consistent with the observation of load reduction due to the deployment of DER and other energy efficient technologies.

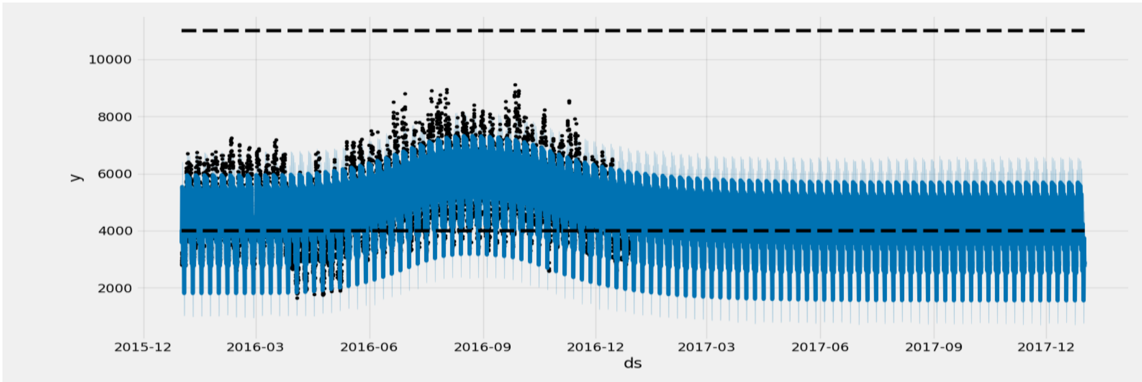


**Figure 39 – Load Scenario for 1 Year with Different Lower and Upper Bounds**

### *6.7.3 Scenario Generation for Multiple Years*

The load scenario for multiple years using lower and upper bounds on the time series data is shown in Figure 40. An uncertainty interval of 80% is used. The upper and lower bounds are used as scenarios. Similar scenarios are constructed for prices and PV values.

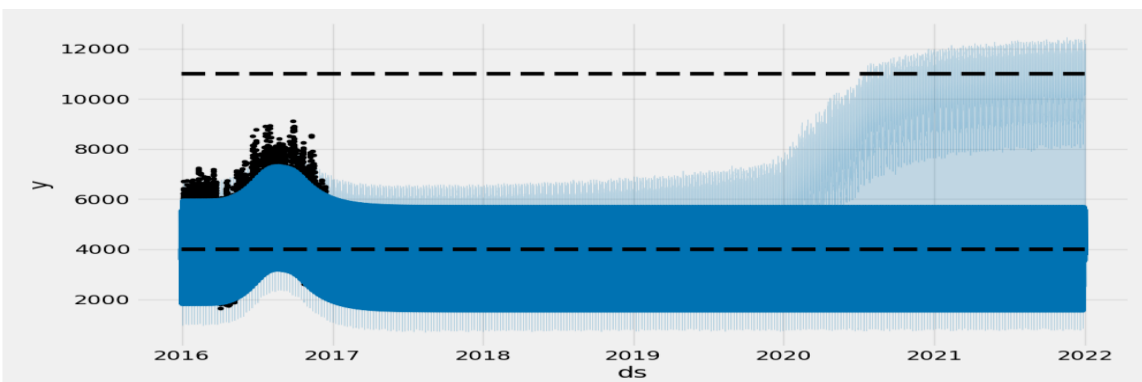


**Figure 40 – Multi-Year Load Scenario with Lower and Upper Bounds**

### *6.7.4 Solar PV Forecast*

The baseline candidate PV profiles are shown in Figure 41. The profiles have different nominal capacities and are shown for the week of peak consumption.

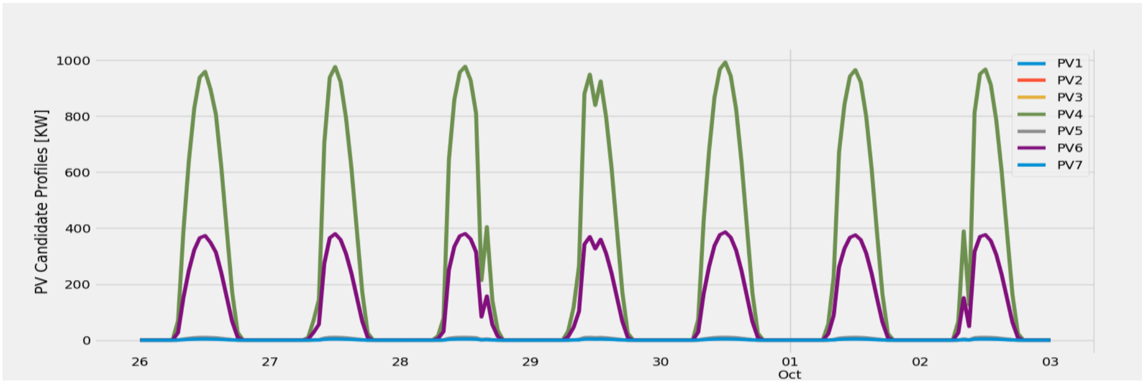


**Figure 41 – Solar PV Baseline Profiles for Candidate Technologies**

### *6.7.5 Investment Costs*

Table 24 shows the investment costs and nominal capacity values used for the candidate DER technologies.

**Table 24 – Investment Costs for Candidate DERs**

| DER Type | Reference Nominal Capacity [kW] | Referential Installed Cost [$] | Assumed Nominal Capacity [kW] | Investment Cost [$/kW] |
|---|---|---|---|---|
| Distributed Generator | 20 | $4,027 | 20 | 201.35 |
| Solar PV 1 [113] | 5.6 | $15,581 | 0.00993 | 2782.32 |
| Solar PV 2 [113] | 5.6 | $15,581 | 0.00745 | 2782.32 |
| Solar PV 3 [113] | 5.6 | $15,581 | 0.00745 | 2782.32 |
| Solar PV 4 [113] | 5.6 | $15,581 | 1.19994 | 2782.32 |
| Solar PV 5 [113] | 5.6 | $15,581 | 0.01241 | 2782.32 |
| Solar PV 6 [113] | 5.6 | $15,581 | 0.46690 | 2782.32 |
| Solar PV 7 [113] | 5.6 | $15,581 | 0.00496 | 2782.32 |
| Energy Storage 1 [114] | 3.3 | $3,000 | 20 | 909.09 |
| Energy Storage 2 [114] | 0.420 | $425 | 12 | 909.09 |

### *6.7.6 Simulation Results for the Week of Peak Demand*

Figure 42 shows the total load and PV power for the baseline case (when one of each of the devices is installed) for the week with the peak load.

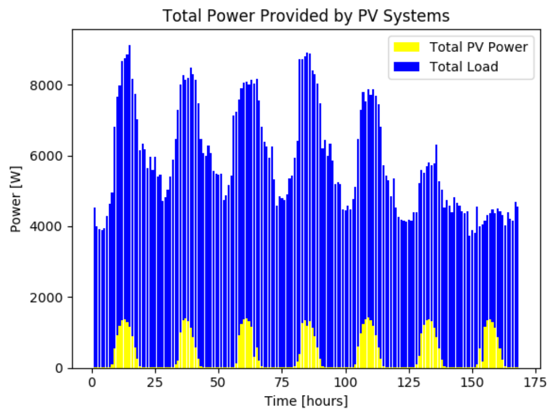


**Figure 42 – Total Load and Total PV Power**

Figure 43 shows the scheduled power for the generator and energy storage device. It is possible to observe that when the load exceeds 95% of the expected forecast, reserves services will be procured.

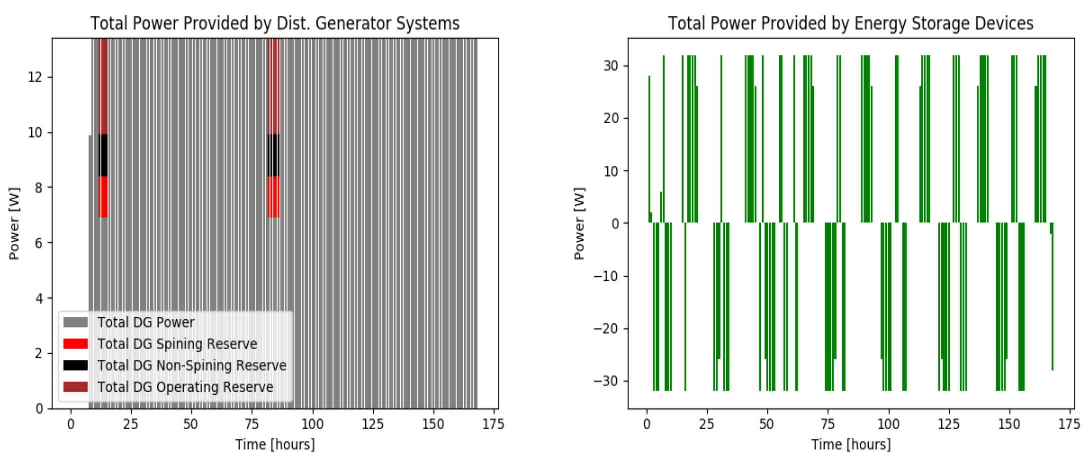


**Figure 43 – Scheduled Power for Generator and Energy Storage**

Figure 44 shows the total system avoided costs for the baseline case for the week of peak consumption.

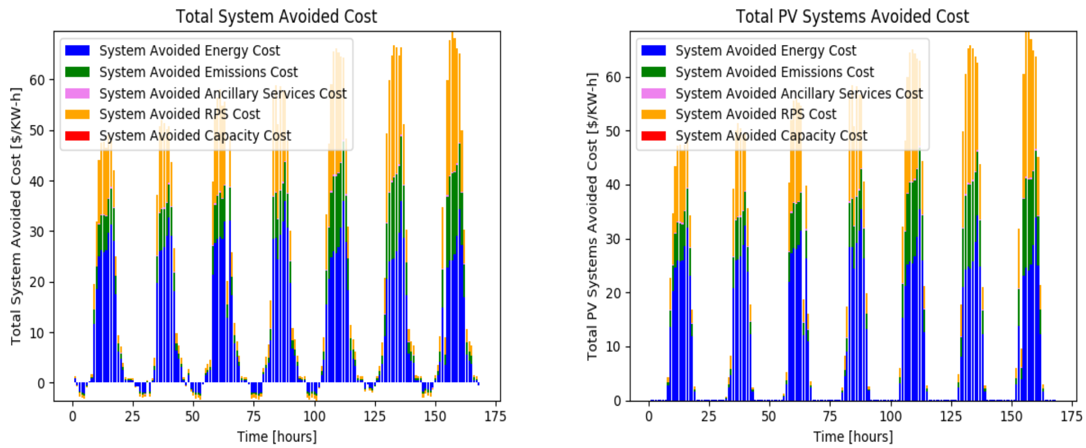


**Figure 44 – Total System Avoided Costs**

Figure 45 shows the total power exchanged at the substation and total PV power when third party covers the majority of the investment costs.

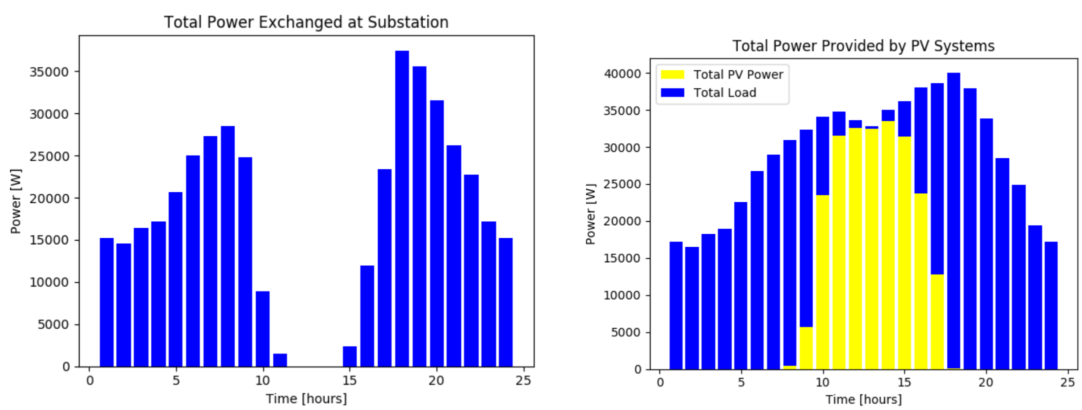


**Figure 45 – Total Power Exchanged at Substation and Total PV Power**

Figure 46 shows the aggregated capacity provided by DERs when a third party covers most of the investment costs. It is assumed that the trend in the load forecast is expected to double every year to show the progression.

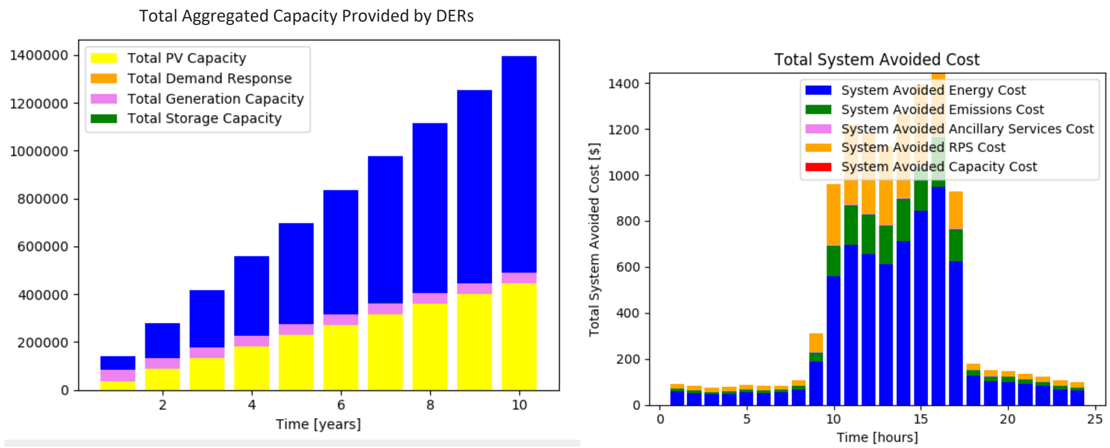


**Figure 46 – Total Aggregated Capacity and Total System Avoided Costs**

## 6.8 Summary

A two-stage stochastic optimization model has been described for minimizing the net present cost of a distributed energy resources portfolio owned by an electric distribution utility who has to decide between deploying a traditional capital investment solution for satisfying a distribution-system peak capacity or a non-wires alternative solution over a multi-year time horizon while taking into consideration operation constraints (power balance, network constraints), financial constraints (timing and value of deferred capital investment) and the uncertainty of the following parameters: wholesale market prices (energy, capacity, ancillary services, emissions), and forecasts (solar radiation, load fluctuation). The parameter uncertainty is represented by scenarios on their values along the planning horizon and the associated probability of occurrence.

The proposed DER Portfolio Valuation Methodology is intended to help in the quantification of the value of a DER portfolio located in a certain distribution system. This methodology aims to make available to electric distribution utilities a systematic approach to: 1) compare DER portfolios as alternatives to traditional grid infrastructure investments, and 2) enhance the distribution planning process in order to: a) integrate higher amounts of renewable energy, and b) facilitate the exchange of grid services by DERs as alternatives to traditional grid infrastructure investments. DER services can be used for (1) optimization resulting in upgrade deferral of grid assets by DER management to shape feeder load and (2) avoided costs through DER participation in wholesale energy markets.

# CHAPTER 7. CONCLUSIONS AND FUTURE WORK

## 7.1 Conclusions

The electric grid is undergoing a profound change driven by regulatory changes, environmental concerns, and changes in customer preferences and advancements in technology. Distributed energy resources (DERs) continue to grow massively. These resources are variable, large in numbers and physically distributed. However, the electric grid was not originally designed to host large numbers of these variables resources. This creates great challenges for electric utilities planning, operations and business models. In response, several regulatory jurisdictions and electric utilities are considering incorporating portfolios of DERs as alternatives or replacements to their traditional capital investments. However, after conducting more than one hundred interviews with electric utility stakeholders it was discovered that the valuation methodologies available to electric utilities only consider system-level average assumptions and do not consider the locational and temporal constraints of these resources. The objective of this dissertation was to develop a new methodology for valuation of DERs located in a specific distribution system. The methodology consists of five steps: 1) a system-level architecture to identify the market regulations and market actors and their interrelations, 2) a prosumer-based benefit-cost framework to identify DER services or value categories, 3) an economic optimization at the bulk power system-level to estimate the aggregated DER impact at the transmission-level, 4) a DER portfolio economic optimization at the distribution system, and 5) an optimization-base valuation method of DER portfolios and economic impact metric such as avoided costs. Major lessons learned from these steps are explained below.

### *7.1.1 Electric Grid Business Model Innovation Framework based on a DER Energy Services Platform Architecture for Renewable Energy Integration*

This chapter presented a Distributed Energy Resources Services Platform Architecture (DERSP) as a Business Model Innovation Framework for Planning of Distributed Energy Resources and Renewable Energy Integration. The framework is based on a multi-layered architecture. The architecture consists of seven layers that describe 1) Devices, 2) Local controllers, 3) Data transmission, 4) System controllers, 5) Market, 6) Planning and 7) Business decision-making. The architecture allows electric grid actors to better understand the complex interrelations of prosumers subsystems equipped with DERs in order to integrate higher amounts of renewable energy. This work has extended previous work on decentralized grid architectures by: 1) formally identifying (a) the market actors (ISO, DSOs, ESCOs, prosumers), (b) the services exchange between them (energy, capacity, ancillary services), and (c) the interactions between actors and system modules across the different architectural layers; 2) including a new business layer that connects investment decision-making with the rest of the layers; and 3) including a new DER planning layer that describes how DER portfolios services are identified, valued and sourced as alternatives to traditional electric utility investments.

The architecture serves as a framework to understand a particular actor's current status, define its objectives, and a template to design a long-term strategy of investment and business model innovation while taking into consideration all the relevant elements of device, communication, system control, planning, and investment decision-making.

### *7.1.2 Prosumer-Based Benefit-Cost Framework for Locational Valuation of Distributed Energy Resources*

The goal of this chapter was to develop a Benefit-Cost Analysis Framework based on the emerging concept of prosumers and a decentralized architecture. A method of locational valuation of distributed energy resources was described, which offers a step-by-step guide to analyzing the value of DERs. The method consists of several steps including: 1) the identification of the DER value chain segment; 2) the identification of market actors, market rules, and interrelations; 3) the identification of the potential service or value categories for DERs that will be exchanged; 4) classification of the impacts as benefits or costs, and the allocation of costs and benefits to different stakeholders within the power system; 5) the identification of how the benefits can be monetized so that all the net impacts are quantified in financial terms; 6) the DER scenario generation; 7) the scheduling of energy operations is obtained either from the DER scheduling or non-optimized schedule; 8) then, a quasi-steady-state-time-series (QSTS) power flow simulation is run to compare the DER scenario with the baseline feeder operation; 9) finally, the impacts on distribution and transmission and associated metrics are calculated. Simulation results are presented for the distribution capacity deferral use case when non-optimized schedules are considered. The framework provides a foundation to evaluate the net benefits of DERs including: avoided energy costs, avoided emissions costs, and avoided capacity costs. The framework was applied to a real distribution system deployed with energy storage, and solar PV systems. The case study revealed that the portfolio can contribute to capacity deferral. However, additional DER portfolio optimization can provide significant improvements.

### *7.1.3 Economic Emissions Dispatch at the Bulk Transmission System Level for Assessment of the Impacts of Aggregated DERs on the Operational Costs of the Grid*

This chapter described a model that consists of several stages that describe generation costs, emission costs, the expected load (including flexibility factors for flexible loads), and renewable generation. The model is able to assess the impact that the aggregated operation of DERs can have on the operational cost of the grid at the bulk system-level while considering all the above-mentioned factors. The model considers the optimization of two objective functions: economic and emissions costs of generation and quantification of aggregated DER impact on reserve requirements. The study also considers the effects of spinning reserve, PV power fluctuations, generation mix, fuel costs, and assesses the possible impact that penetration of photovoltaic generation and aggregated DERs would have in the operational cost of the grid. Simulation results using the year load data for the State of Georgia are presented. First, in order to model and assess the impact of the requirement for spinning reserve, the peaking generation (gas turbines) is modeled as ten power plants of equal capacity. Second, the spinning reserve is introduced into consideration. The generation is constrained to operate at 110 percent of the daily peak load whenever the load exceeds 95 percent of the daily peak. The economic optimization is applied to obtain the new hourly annual simulation. The results generated are compared and contrasted with the data obtained without spinning reserve consideration. Lastly, in order to offer economic indicators to possible investors, the results are analyzed by the DER Economic Value-Added method. The simulation results show that as the factor of DER flexibility increases, total costs and total emissions are reduced.

### 7.1.4 DER Portfolio Economic Optimization at the Distribution Level

A new DER portfolio economic optimization at the distribution level was presented. A mixed integer linear programming model is presented that describes different stages of modeling including: energy storage constraints, generator model constraints, flexible demand constraints, power balance constraints, reserve constraints and line constraints. The model is demonstrated in two use cases. The first use case is related to a campus acting as a virtual power plant that is exposed to a time varying price signal. In this case the major decision variables are associated with the flexible load. Results show that significant cost reductions are achieved using optimization while maintaining comfort defined bounds. The second use case is related to a distribution system operator that is interested in operating a portfolio of DERs at the minimum cost. Results are presented from the standpoint of total system avoided costs obtained from the DER economic optimization. This leads to the conclusion that when optimization is applied to a DER portfolio significant benefits can be obtained by avoiding energy costs, emissions and capacity costs.

### 7.1.5 DER Locational Valuation Based on a Two-Stage Stochastic Integer Optimization with Risk Aversion

A two-stage stochastic optimization model was presented for minimizing the net present cost of a distributed energy resources portfolio owned by an electric distribution utility who has to decide between deploying a traditional capital investment solution for satisfying a distribution-system peak capacity or a non-wires alternative solution over a multi-year time horizon while taking into consideration operation constraints (power balance, network constraints), financial constraints (timing and value of deferred capital investment) and the uncertainty of the following parameters: wholesale market prices (energy, capacity, ancillary services, emissions), forecasts (solar radiation, load fluctuation). The parameter uncertainty is represented by scenarios on their values along the planning horizon and the associated probability of occurrence. The method was applied to a realistic feeder. The model is able to obtain the optimal DER portfolio that minimizes total investment costs and expected operational costs while satisfying specific market, grid, and DER locational and temporal constraints. The use case also confirms that the value of a DER depends on: the network topology, DER location, market constraints, and how the DER is operated.

The proposed DER Portfolio Valuation Methodology is intended to contribute to the quantification of the value of a DER portfolio located in a certain distribution system. This methodology aims to make available to electric distribution utilities a systematic approach to:

1. Compare DER portfolios as alternatives to traditional grid infrastructure investments,

2. Enhance the distribution planning process in order to:

a) Integrate higher amounts of renewable energy, and

b) Facilitate the exchange of grid services by DERs as alternatives to traditional grid infrastructure investments.

DER services can be used for (1) optimization resulting in upgrade deferral of grid assets by DER management to shape feeder load and (2) avoided costs through DER participation in wholesale energy markets.

## 7.2 Summary of Contributions

In this dissertation, an optimization-based valuation methodology of DER portfolios was described. The contributions of this dissertation are as follows:

1. Extending and improving a prosumer-based decentralized grid architecture by:

(a) Identifying the market actors (ISO, DSOs, ESCOs, prosumers),

(b) Identifying the services exchanged between them (energy, capacity, ancillary services), and

(c) Identifying the interactions between actors and system modules across the different architectural layers;

2. Developing a new business layer that provides a framework for investment decision-making and valuation of traditional and DER portfolios services as value propositions by considering regulatory guidelines, market rules, business objectives, planning constraints, system constraints, device constraints and grid model specified by the lower layers of the architecture.

3. Developing a new DER planning layer that describes how DER portfolios services are identified, valued and sourced as alternatives to traditional electric utility investments.

4. Developing a benefit-cost framework for DER valuation that goes beyond average top-down assumptions and models DER locational and temporal constraints. Its unique characteristics include:

a) Going beyond system level assumptions based on top down approaches and considering locational and temporal characteristics of DERs,

b) Proposing a method where valuation actively models the grid, DERs, considers market constraints and the services exchanged among them.

5. Developing an economic-emissions optimization model at the bulk system level considering the aggregated DER impact.

6. Developing a mixed integer programming model for DER portfolio economic scheduling optimization at the distribution system considering reserves, avoided costs, and detailed generator, energy storage and demand response constraints.

a) Considering the simultaneous net effect that a portfolio of devices such as energy storage, solar PV, distributed generation, and demand response could provide while taking into consideration market, system and device-level constraints.

b) Considering system avoided costs (such as avoided energy, avoided capacity, avoided ancillary services, avoided renewable portfolio standard), in the objective function

c) Considering reserve services and detailed generation models including startup, shutdown cost, and minimum up and down times

7. Developing a two-stage stochastic optimization model for distribution level capacity expansion, DER valuation and assessment as non-wire alternatives.

8. Developing a risk averse two-stage stochastic optimization model for distribution level capacity expansion and DER valuation and assessment as non-wire alternatives.

**Table 25 – Unique Characteristics of DER Valuation Methodology**

| **Metric** | **Legacy Modeling** | **Proposed DER Portfolio Valuation Methodology** |
|---|---|---|
| DER Types | Individual DER Valuation (i.e. only PV) | Integrated (combined and simultaneous effect of various DER types) DER Portfolio Valuation |
| System Constraints | Spreadsheets with some market and financial constraints | Consideration of physical, market, and DER locational-temporal constraints |
| T-D Value categories | There has not been consideration of integrated T/D | Consideration of Transmission and Distribution value categories |
| DER Schedule | Heuristic | Economic optimization of DER operation |
| Demand Input type | Snapshots (i.e. worst peak day) of worst-case scenarios | Forecasts of full-year DER operation |
| Granularity | Low resolution (only average system-level values), no locational or temporal granularity | Locational and temporal specificity complemented with Quasi-steady state analysis for one year at one-hour granularity at specific feeder location |

## 7.3 Future Work

This dissertation has explored the valuation of DER portfolios using optimization models while taking into consideration system constraints, market constraints and DER locational and temporal constraints. There are several future areas of research. Potential future work can be categorized in the following categories:

1. DER Types: The models can be expanded by including stochastic models of electric vehicles.

2. Distribution Value Categories: Considering shorter time scales such as voltage, frequency regulation, reliability services, and other services enabled by smart inverters.
3. DER Scheduling: The models can be expanded by considering multiple decentralized-objectives of several agents.
4. Demand Input Type: The models ideally can be improved by interconnecting directly with electric utilities databases and long-term forecasts that use satellite images, econometric-factors to provide a long-term estimate of the DER and load forecasts.
5. Granularity: The research can be expanded to consider faster time scales including sub second services.
6. System Constraints: a) Multi-energy systems: the models can be expanded to consider detail thermal models of buildings; b) Smart-city planning: the models can be combined with city planning constraints such as land usage and transportation planning models to generate an integrated smart city planning framework; c) Integrated DER-network planning: the models can be expanded to consider optimal network planning and reconfiguration together with DER planning.

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